U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No: 50-397/93-13

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 30 - May 10, 1993

Inspectors: R. C. Barr, Senior Resident Inspector
D. L. Proulx, Resident Inspector
W. L. Johnson, Resident Intern

Approved by: P. H. Johnson, Chief
Reactor Projects Section 1

6/8/93
Date Signed

Summary:

Inspection on March 30 - May 10, 1993 (Report No. 50-397/93-13)

Areas Inspected: Routine inspection by the resident inspectors of control room operations, licensee action on previous inspection findings, operational safety verification, surveillance program, maintenance program, licensee event reports, special inspection topics, and procedural adherence. During this inspection, Inspection Procedures 61726, 62703, 71707, 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.

Strength: Operations management initiated an Operations "time out" during this inspection period to discuss performance issues identified during the outage and to emphasize the importance of proceeding in a careful and deliberate manner (Paragraph 4.b).

Summary of Violations and Deviations: Two violations were identified. One violation involved the failure to follow procedures (Paragraph 6). The other violation involved the failure to maintain drawings current (Paragraph 5).

Open Items Summary:

One followup item and two LERs were closed; four new items were opened.

DETAILS

1. Persons Contacted

V. Parrish, Assistant Managing Director for Operations
*J. Gearhart, Quality Assurance Director
*J. Baker, Plant Manager
*G. Smith, Operations Division Manager
*R. Webring, Technical Services Manager
*L. Harrold, Maintenance Division Manager
*L. Grumme, Nuclear Safety Assurance Manager
G. Sorensen, Regulatory Programs Manager
*D. Pisarcik, Radiation Protection Manager
*G. Gelhaus, WNP-2 Projects Manager
A. Hosler, Licensing Manager
S. Davison, Quality Assurance Manager
*J. Peters, Administrative Manager
W. Shaeffer, Operations Manager
*T. Messersmith, Maintenance Support Manager
*D. Schumann, Acting Operational Events Analysis and Resolution Manager
*C. Fies, Licensing Engineer
G. Brastad, Engineer

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

*Attended the Exit Meeting on May 27, 1993.

2. Plant Status

At the start of the inspection period, the plant was in Mode 1 (Power Operation) at 99% power. On April 15, 1993, the plant developed a small condenser tube leak that caused reactor water conductivity to increase to a maximum of 0.51 umhos/cm. When operators reduced reactor power, the conductivity decreased to approximately 0.17 umhos/cm. Due to the potential for increasing the size of the tube leak during plant power maneuvers, management decided that operators should not perform planned rod pattern changes. Therefore, reactor power had coasted down to 91% power at the time of the April 30, 1993, reactor shutdown for the annual refueling outage.

The reactor was scrammed as part of the normal shutdown evolution on May 1, 1993. Operators then commenced plant cooldown and entered Mode 4, Cold Shutdown, on May 2, 1993. During the cooldown, several 6-inch reactor water level deviations of approximately one minute duration were observed. When reactor temperature was less than 140 degrees, the licensee commenced drywell and reactor disassembly. On May 3, 1993, operators placed the reactor in Mode 5, Refueling. After completing reactor disassembly, the licensee commenced core alterations. On May 10, 1993, the plant experienced a loss of the 500 kilovolt (KV) backfeed,

which at that time was serving as the primary source of offsite power (Paragraph 4.a). This resulted in an automatic isolation of shutdown cooling, starting of the Division 1 and 3 diesel generators (DGs), and the automatic transfer of Division 1 safety-related loads to the backup transformer. Core alterations were suspended. Offsite power was subsequently restored to the startup transformer, and shutdown cooling reinitiated. The plant was in Mode 5, with core alterations in progress, at the end of the inspection period.

3. Previously Identified NRC Inspection Items (92701, 92702)

The inspectors reviewed records, interviewed personnel, and inspected plant conditions relative to licensee actions on previously identified inspection findings:

a. Unresolved Item 397/93-06-02 (Closed): End of Cycle (EOC) Recirculation Pump Trip (RPT) Due to Inadequate Surveillance

During a previous inspection period, the licensee found that the EOC RPT breakers had not been properly tested. Technical Specification (TS) 4.3.4.2.3 required the RPT breakers to be tested every 60 months to verify that the breaker arc suppression time was less that 83 milliseconds. The procedures that the licensee used to conduct these tests initiated the trip through the actuation of a different trip coil (TC-1) than the trip coil which performs the safety function for the breaker (TC-2). During this inspection period, the licensee tested the arc suppression time using the correct trip coil after the plant was shutdown. The arc suppression time was well within the TS limits. Therefore, this finding had no safety significance. The inspector reviewed the LER associated with this event and reviewed the completed surveillance data for the properly completed test. The inspector considered the test results and related corrective actions identified in LER 93-10 to be satisfactory (the LER remains open for review of actions related to other issues). This item is closed.

4. Event Followup (93702)

a. Loss of 500 KV Backfeed and Engineered Safety Features Actuations

On May 10, 1993, the offsite power source in use, 500KV backfeed, tripped and offsite power did not fast-transfer to the startup transformer (230KV, TR-S). The backup transformer (115KV, TR-B) transferred and powered loads on SM-7, the vital bus for Division 1 power supplies. However, because SM-8 was in an outage with bus restoration in progress and the TR-B feeder breaker for SM-8 (Division 2) was in pull-to-lock, SM-8 did not automatically reenergize. Due to the electrical line-up during this perturbation, several ESF actuations occurred. The Division 1 and 3 DGs started, the Division 3 DG powered bus SM-4, and shutdown cooling isolated. Operators manually transferred loads to TR-S, secured the DGs and recovered shutdown cooling in approximately 30 minutes. Reactor temperature increased about 1.7 degrees during this period.

The inspectors were in the control room when the event occurred. The operators' response to the event was timely and per plant procedures. However, the inspector noted that if TR-B had been in an outage, as was allowed by the TS, and if the fast transfer had not occurred, as was the case during this event, the plant would have had a complete loss of offsite power.

The licensee's preliminary investigation determined that on May 10, 1993, the Bonneville Power Administration (BPA) load dispatcher in Vancouver, Washington was operating breakers located at the Ditmer Substation (also in Vancouver) to remove reactive load from the grid. However, the load break disconnect (LBD) for the B phase of one inductor did not open. The interlock associated with this LBD sensed an overcurrent situation which resulted in the opening of several 500KV breakers on the BPA grid, including one of the two 500KV breakers which connect WNP-2 to the Ashe Substation (the other WNP-2 500KV breaker was already open). Because there was no fault on the line side of the licensee's 500 KV breaker, a fast transfer to TR-S did not occur and was not expected to occur.

The licensee determined that the LBD failed because an internal switch in the LBD malfunctioned. The cause of the switch malfunction has not yet been determined. The Supply System stated that BPA is investigating the cause of the LBD switch failure. The licensee is submitting an LER for this event.

b. Operations Time Out

On May 1, 1993, the reactor was shut down for the R-8 refueling outage. The licensee immediately started reactor disassembly, preparations for core alterations and divisional outage work. At the end of the inspection period, the outage was on schedule with numerous work activities in progress. However, licensee personnel initiated five problem evaluation requests (PERs) early in the outage related to errors committed by Operations personnel. These errors included problems with clearance orders and the implementation of operating procedures.

Because the Operations Manager was concerned about the pattern of poor performance, he initiated an Operations "time out." All work was stopped on all three shifts to discuss the above issues. The Operations Manager emphasized that the above performance issues were unacceptable and must not continue. Although the "time out" represented good initiative in recognizing and addressing performance issues, the inspector noted that most of the problems indicated poor equipment operator (EO) performance. NRC Inspection Report 50-397/93-04, "Systematic Assessment of Licensee Performance (SALP)," discussed other issues associated with EO performance. The SALP report noted that EO performance had declined during the most recent assessment period. During a weekly meeting, the Plant Manager acknowledged the inspector's comments.

No violations or deviations were identified.

5. Operational Safety Verification (71707)

a. Plant Tours

The inspectors toured the following plant areas:

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

b. The inspectors observed the following items during the tours:

(1) Operating Logs and Records. The inspectors reviewed records against Technical Specification and administrative control procedure requirements.

(2) Monitoring Instrumentation. The inspectors observed process instruments for correlation between channels and for conformance with Technical Specification requirements.

(3) Shift Manning. The inspectors observed control room and shift manning for conformance with 10 CFR 50.54.(k), Technical Specifications, and administrative procedures. The inspectors also observed the attentiveness of the operators 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. The inspectors verified valves and electrical breakers 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. The inspectors observed fire fighting equipment and controls for conformance with administrative procedures.

(8) Plant Chemistry. The inspectors reviewed chemical analyses and trend results 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.

a. On April 14, 1993, during a tour of the radiologically controlled area (RCA), inspectors identified numerous examples that indicated personnel had been eating or smoking in the RCA. Eating, drinking and smoking in the RCA are contrary to licensee HP procedures. The inspector found evidence of sunflower seeds, candy, gum wrappers, and cigarette butts in the reactor building. The inspector notified the lead health physics technician (HPT). The HPT located the material, removed it from the RCA, and initiated a Problem Evaluation Request (PER). The inspector discussed this issue with the Plant Manager (PM) who stated that a number of similar occurrences had been identified by plant management. The PM stated that personnel action would be taken for any person caught in the RCA eating, drinking, or smoking. In addition, the PM issued an all employee bulletin to discuss the seriousness of such an occurrence. Subsequently, the licensee found two individuals violating RCA requirements and took appropriate action.

b. On May 5, 1993, during a tour of the reactor building, the inspectors found that Regulated Air Sampling (RAS) pump RB-4R was operating past its calibration due date. The due date indicated May 1, 1993. The inspector notified HP, who changed out the RAS pump with a unit that had been recently calibrated. The licensee initiated a PER to determine the root causes of this occurrence. The HP supervisor stated that although they were required to change out the RAS pumps prior to the calibration due date, RB-4R was not out of calibration because it was not in use past its late date (an additional 25% of the calibration interval).

The licensee uses RAS pumps on each floor of the reactor building to trend particulate and iodine airborne radioactivity on a weekly basis. NRC Inspection Reports 50-397/92-03 and 50-397/93-06 describe additional problems the licensee has had in controlling these instruments. Therefore, it appears additional management attention to

maintenance of these instruments is warranted. The HP supervisor briefed the HP staff on these problems, and changed the process in the Scheduled Maintenance System (SMS) to more clearly denote the calibration due dates of the RAS pumps to preclude further recurrence. The inspector reviewed the licensee's actions, which appeared satisfactory.

(10) Plant Housekeeping. The inspectors observed plant conditions and material/equipment storage 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.

(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 Features Walkdown

The inspectors walked down selected engineered safety features (and systems important to safety) 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.

The inspectors walked down accessible portions of the following systems on the indicated dates:

System	Dates
Diesel Generator Systems, Divisions 1, 2, and 3.	May 10
Low Pressure Coolant Injection (LPCI) Trains A, B, and C	April 16
Low Pressure Core Spray (LPCS)	May 3
High Pressure Core Spray (HPCS)	May 3
Reactor Core Isolation Cooling (RCIC)	May 1, 3, 10

Residual Heat Removal (RHR), Trains A and B	April 16
Standby Gas Treatment (SGT) System	May 1
Standby Liquid Control (SLC) System	May 3
Standby Service Water (SSW) System	April 16
125V DC Electrical Distribution, Divisions 1 and 2	May 3
250V DC Electrical Distribution	May 3

NRC Inspector Observations

(1) During the tour of the "B" SSW pumphouse on April 16, 1993, the inspector found that several of the cable trays and safety related conduits in the pumphouse were protected by Thermolag System 330 fire retardant material. Although the inspectors spent more than an hour walking down the SSW system, they noted that a fire tour was not performed in the area. The inspectors contacted the Shift Manager, who stated that the SSW pumphouses were not on the fire tour. Discussions with the licensee indicated that they were unaware that Thermolag was installed in this area. The licensee initiated a PER, and temporarily added the SSW pumphouse to the fire tour until the issue was resolved.

The licensee's investigation revealed that the Thermolag was installed for train separation considerations, and not as a one- or three-hour fire barrier per Appendix R of 10 CFR 50. Based on this determination, the licensee terminated performance of fire tours of the SSW pumphouse. The inspectors discussed this issue with a representative of the NRR Inspection and Licensing Policy Branch, who stated that although the Thermolag system was inoperable to meet the Appendix R requirements, it was considered to be operable for train separation purposes. The licensee determined that the root cause of their not being aware that Thermolag was installed in the SSW pumphouse was that its installation was not reflected in the applicable drawing (E-797). The failure to maintain drawings current is a violation of 10 CFR 50, Appendix B, Criterion V (Violation, 50-397/93-13-01).

The inspectors also determined that, because the licensee was previously unaware of the installation of Thermolag in this location, the licensee would not have performed cabling ampacity derating calculations to which they had committed in their response to NRC Generic Letter 92-08.

In the licensee's research of this issue, they identified several other plant areas where Thermolag was installed but not reflected on the drawings. These instances were either where

the Thermolag had been installed for cable separation, or where the licensee had previously determined that the Thermolag was not necessary to meet regulatory requirements and had abandoned it in place. The inspector noted that none of these electrical conduits or cable runs had had their ampacity derating calculation performed. Because the plant drawings were not current with the plant configuration, the licensee apparently could not positively state that they were knowledgeable of all of the plant areas where Thermolag was installed. This issue is potentially significant due to the possibility of finding safety-related cabling undersized based on the ampacity derating.

The licensee stated that they would perform a thorough plant walkdown, identify all areas that contain Thermolag, and update the appropriate ampacity derating calculations. Inspector followup of this issue will be accomplished during followup on Violation 93-13-01.

(2) During the walkdown of the HPCS system on May 3, 1993, the inspector found that the flange downstream of HPCS-V-12 was leaking at about 20 drops per minute. The inspector notified the Shift Manager and HP. The HP Technician surveyed the area, which was contaminated, and wrapped the flange with yellow PVC. A maintenance work request (MWR) was initiated to correct the leak.

Further investigation by the inspector found that this flange is unisolable from the containment structure. Because this flange was found leaking, the inspector noted that this was an unanalyzed leak path out of primary containment, and may pose a containment integrity problem. Further, TS 6.8.4 required the licensee to implement a program to reduce leakage from those portions of systems that could contain highly radioactive fluids during a serious accident. One of the systems included in this TS is HPCS. In addition, this TS required periodic visual examinations, and leak rate tests of this system. The licensee stated that they would perform an evaluation of this deficiency. Until the licensee completes their evaluation, this issue is unresolved (Unresolved Item, 50-397/93-13-02).

One violation was identified.

6. Surveillance Testing (61726)

The inspectors reviewed surveillance tests required by Technical Specifications (TS) 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; (3) test results satisfied acceptance criteria or were properly dispositioned; and (4) procedures were followed in accordance with administrative procedures.

a. The inspectors observed portions of the following surveillances on the dates shown:

Procedure	Description	Dates Performed
7.4.0.5.55	Main Steam Relief Valve Setpoint Verification	May 1, 1993
7.4.3.1.1.63	Average Power Range Monitor (APRM) Channel B Channel Functional Test (CFT)	May 5, 1993
7.4.3.1.1.65	APRM Channel D CFT	May 5, 1993
7.4.3.1.1.66	APRM Channel E CFT	May 5, 1993
7.4.3.1.1.67	APRM Channel F CFT	May 5, 1993
7.4.9.6	Refuel Platform Crane and Hoist Interlock Surveillance	May 5, 1993

During performance of PPM 7.4.0.5.55 the inspector witnessed the system engineer (SE), who was covering the surveillance, take two keys out of his pocket and open two remotely operated valves. Upon review of a working copy of the procedure, the inspector noted that steps 7.28 and 7.30 state "have an Operator place the key lock switch...to the ON position." When the inspector questioned the SE on this practice, the SE indicated that the Shift Manager (SM) had given him permission to go ahead and open the valves. When the inspector continued to question this practice, the Technical Manager stated that the licensee would treat this problem as a verbal procedure deviation (temporary change), and proceeded to the control room to ask the SM to address the approach in this manner. The licensee approved a formal deviation to the procedure before the end of the day, as required. The inspector discussed this issue with the Plant Manager (PM) on May 6, 1993. The inspector noted that the licensee had followed the verbal deviation procedures, but questioned whether this would have happened if the inspector had not questioned the actions of the SE. The Plant Manager acknowledged the inspector's comments.

b. The inspectors reviewed completed surveillance procedures to determine the effectiveness of corrective actions from previous NRC inspections. The inspectors requested that the licensee provide copies of 15 recently completed surveillance procedures, spread evenly among Operations, Instrumentation and Controls (I&C), and Electrical Maintenance personnel. On April 12, 1993, the licensee provided the following procedures for the inspector's review:

Procedure	Title	Date Performed
7.4.8.2.1.20	Weekly Battery Testing	April 7, 1993

7.4.3.6.22	Control Rod Block Recirc. Flow D Inop, Upscale and Comparator CFT	April 1, 1993
7.4.4.3.1.3	Drywell Sump Flow Monitors CFT	April 7, 1993
7.4.3.7.1.15	Spent Fuel Storage Pool Area Radiation Monitor CFT	April 1, 1993
7.4.3.7.4.10	Spray Pond B Level	April 7, 1993
7.4.0.5.4	Fuel Pool Cooling System Operability Test	April 2, 1993
7.4.0.5.4	Fuel Pool Cooling System Operability Test	April 6, 1993
7.4.6.4.2.6	Reactor Building-Suppression Chamber Vacuum Breaker and Actuation Instrumentation CFT	April 5, 1993
7.4.8.2.1.20	Weekly Battery Testing	April 1, 1993
7.4.6.6.1.1	CAC-HR-1A Preheater Operability Test	April 12, 1993
7.4.1.3.1.2	Control Rod Exercise	April 12, 1993
7.4.6.1.1	Primary Containment Integrity Verification	April 12, 1993
7.4.8.1.1.2.12	HPCS Diesel Generator Monthly Operability Test	April 12, 1993
7.4.8.1.1.2.1	Diesel Generator 1 - Monthly Operability Test	March 8, 1993
7.4.8.1.1.2.1	Diesel Generator 1 - Monthly Operability Test	April 4, 1993

The inspector reviewed these completed procedures per PPMs 1.2.3, "Use of Controlled Plant Procedures," and 1.5.1, "Technical Specification Surveillance Program." Only five of the reviewed procedures indicated proper conduct and documentation of the associated surveillances. The inspector identified the following discrepancies:

<u>PPM 7.4.3.7.4.10, Spray Pond B Level (performed April 7,1993)</u>

- On Table 7.1a, the craftsman entered 11.1 feet as the "as-found" and "as-left" values. The Table lists the acceptable range as 11.75 to 12.25 feet. The craftsman signed off step 7

of section 7.1 of the procedure signifying that all values in Table 7.1a were within the stated tolerance.

- On Table 7.1b, the craftsman entered 11.0 feet as the "as-found" and "as-left" values, but the acceptable range was listed as 11.75 to 12.25 feet. The craftsman signed off step 7 of section 7.2, which required the user to verify that all values were within the stated tolerance, as satisfactory.

- Step 8 of section 7.1 required the user to mark steps 9 through 12 "N/A" if the answer to step 7 was "YES." (Steps 9 through 12 required adjustment of the instrument if the data was out of specification). Step 7 was marked "YES," but steps 9 through 12 were signed off as performed.

- On Table 7.4a, three data recording errors were made, but the craftsman corrected the errors by writing over the previous entry. Paragraph 5.1.10 of PPM 1.2.3 states "when recording errors are made, a single line shall be drawn through that entry and initialed and dated. Do not ... write over the entry."

  The inspector discussed the issue of recording out-of-specification data as listed above with the craft supervisor. The craft supervisor considered that since the procedure was in error, the craftsman could consider the problem to be "just a typo" and continue on with the procedure. However, PPM 1.2.3 stated that if one noted such an error, the user was required to stop and request a procedure change. The inspector reviewed the instrument master data sheets (IMDS) to ascertain what should be the correct setpoint range for the values stated above. The IMDS indicated that the correct range was 10.75 to 11.25; therefore, the instrument was operable. However, these examples appear to demonstrate that licensee personnel did not fully understand the requirements for following their procedures.

<u>PPM 7.4.8.1.1.2.1, Diesel Generator 1 - Monthly Operability Test (performed April 4, 1993)</u>

- Section 7.5, steps 80 and 81 required the operator to record the level of diesel oil tank DO-TK-1A in feet and inches and then convert this value to gallons, based on the table in Attachment 9.4. The operator entered 11 feet, zero inches, which corresponds to 57,251 gallons in the table of Attachment 9.4. However, the operator had entered 57,635 gallons in step 81, a non-conservative value that was not found on the Table in Attachment 9.4.

- The signature block for Step 7.1 was left blank. This step was a prerequisite that required the user to obtain all proper materials and test equipment prior to commencing the surveillance. PPM 1.2.3 required that all signature blocks and data entries either be signed off or marked "N/A."

- Step 46 of Paragraph 7.5 required the user to mark the step as "N/A" if starting air pressure was less than 206 psig, as noted in step 45. However, step 45 was signed off as satisfactory (i.e. less than 206 psig) yet step 46 was not marked N/A, and was signed off as performed.

- The Table in Attachment 9.3 contained data blocks for various diesel engine parameters to be recorded while the engine was running, after the diesel was fully loaded, and after 1 hour and 2 hours of run time. All of the data blanks for after 2 hours of run time were left blank, contrary to PPM 1.2.3, which required all data blanks to be filled in or marked as "N/A."

PPM 7.4.8.2.1.20, Weekly Battery Testing (performed April 7, 1993)

- Attachment 9.1 has a table for recording various parameters of the battery, with a section for comments at the bottom. The craftsman entered comments stating that cell number 17 appeared to have a high electrolyte level, and that an engineer's concurrence was required to determine if the level was satisfactory. In addition, the craftsman indicated that sedimentation appeared to be high in cells 6 and 11, and an engineer's concurrence was also required for this apparent deficiency. The licensee did not document resolution of these comments, contrary to PPM 1.2.3, and the procedure was signed off as satisfactorily completed.

  In addition, the craftsman indicated that he had issued a Repetitive Task Request (RTR) to lower electrolyte level. The inspector questioned the issuance of an RTR for two reasons. First, TS 4.8.2.1.a, Table 4.8.2.1-1 required that if high electrolyte level (1/4 inch above the high level marking) is noted, the licensee is required to adjust the value of specific gravity based on electrolyte level. The inspector's second concern was that the procedure for an RTR does not permit lowering battery electrolyte level using an RTR. An MWR would be the proper vehicle for this task. The licensee stated that the engineer found the electrolyte level to be satisfactory, but did not consider it necessary to document his conclusions. In addition, the licensee stated that they do not normally adjust the specific gravity reading for electrolyte level. Rather, they lower level in the battery, and take another complete set of data. The inspector questioned this practice because it did not appear that the battery would have good mixing, and because the licensee did not perform an equalizing charge after lowering level. The licensee's actions did not appear to meet the intent of IEEE 450-1975. The inspector will review the licensee's practice for resolving high electrolyte level in a future inspection (Followup Item, 50-397/93-13-03).

PPM 7.4.1.3.1.2, Control Rod Exercise (performed April 12, 1993)

- Steps 7.f and 7.j of section 7.0 required the user to record any problems noted with the control rods exercised during

performance of the procedure, including unavailable or lost rod position indication, in Attachment 9.3. Contrary to these procedure requirements, the table in Attachment 9.2 containing signoffs that each rod was exercised satisfactorily had comments indicating that rod position indication was lost for control rod 34-19 at positions 4 and 6, but no entry was made in Attachment 9.3 in the rod exercising problems list.

PPM 7.4.8.1.1.2.1, Diesel Generator 1 - Monthly Operability Test (performed March 8, 1993)

- Step 7 of Paragraph 7.3 required the user to verify that the oil sump low level alarm was not actuated. The user signed off this step as satisfactory, but indicated on the cover sheet of the procedure that the alarm was actuated due to the microswitch of the alarm being broken. PPM 1.2.3 required the user to "N/A" steps associated with minor problems that prevent a step from being satisfactorily accomplished, then annotate on the cover sheet the reason for the "N/A."

- Steps 11 and 80 of sections 7.6 required the user to measure fuel oil storage tank levels in feet and inches, and convert this level to gallons based on the table in Attachment 9.4. This table only provided values to the nearest inch. In both steps 11 and 80, the operators recorded level in fractions of an inch. However, in step 11 the user interpolated between the two values; while in step 80, the user recorded the value from the table to the nearest inch. The procedure did not give any direction whether to record level to the nearest inch, or to interpolate for fractions of inches. This weakness appears to have led to the apparent inconsistency discussed above.

- Similar to the findings for the PPM 7.4.8.1.1.2.1 surveillance performed on April 4, 1993, all of the data blocks for the data taken after 2 hours of running time were left blank, contrary to PPM 1.2.3.

PPM 7.4.8.1.1.2.12, HPCS Diesel Generator Monthly Operability Test (performed April 12, 1993)

- Section 7.2 required the user to complete an electrical checklist, which includes verifying that the diesel's air compressor battery charger breaker was in the "ON" position. The user annotated on the cover sheet that this breaker was tagged in the "OFF" position. PPM 1.2.3 required such steps to be marked as "N/A."

- Similar to the findings for both performances of PPM 7.4.8.1.1.2.1, all of the data blocks for the data taken after 2 hours of running time were left blank, contrary to PPM 1.2.3.

- Step 67 of Paragraph 7.6 was signed off indicating that all parameters listed in Attachment 9.3 were within the limits

specified in the log sheets. However, the block for lube oil soakback pump DLO-P-10 running was entered as "OFF" while the required position listed in Attachment 9.3 was "ON." The operator annotated on the cover sheet of the procedure that DLO-P-10 was supposed to be normally off, and that DLO-P-12 was the normally operating pump. It appears that PPM 1.2.3 required a procedure deviation to be issued for errors in tables such as this.

PPM 7.4.6.1.1, Primary Containment Integrity Verification (performed April 12, 1993)

- Step 4 of Paragraph 7.0 of this procedure stated that independent verification of the position of the containment isolation valves listed was only required if this procedure was being performed following a refueling outage. The Operations Manager stated that this statement was recently added to the procedure to reduce radiation exposure among the operations personnel. However, 56 of the valves listed were independently verified, despite the direction of Step 4.

- Step 4 of Paragraph 7.0 also stated that approximately 70 valves in the procedure are marked to indicate that local verification is not required during plant operation. This step then states that these valves are verified indirectly by satisfactorily performing leak detection surveillances on the areas containing these valves. However, this procedure contained no provisions to directly verify the positions of these valves, should any of the leak detection surveillances fail. The inspector will follow this issue to determine if this method appears to meet the intent of the TS when a leak detection surveillance is unsatisfactory (Followup Item, 50-397/93-13-04).

PPM 7.4.6.4.2.6, Reactor Building-Suppression Chamber Vacuum Breaker and Actuation Instrumentation CFT (performed April 5, 1993)

- PPM 1.2.3 required the user to indicate in the blocks provided on the cover sheet whether or not the test was satisfactory, a PER was initiated, or an MWR was initiated. All of these blocks were blank on the cover sheet of the completed copy of this procedure.

PPM 7.4.3.7.1.15, Spent Fuel Storage Pool Area Radiation Monitor CFT (performed April 1, 1993)

- PPM 1.2.3 required the user to verify the procedure prior to use, and document this verification by signing in the preprinted block provided, or stamp the procedure "Verify prior to Use", and sign in the block provided on the stamp. However, the procedure did not contain a preprinted verification block, and the user did not stamp the procedure as mentioned above.

PPM 7.4.6.6.1.1, CAC-HR-1A Preheater Operability Test (performed April 12, 1993)

- The user signed off Step 25 of Section 7.0 as complete, when it should have been marked "N/A." This step required the user to clear a danger tag, although the procedure indicated elsewhere that a danger tag was never hung.

For all of the above discrepancies, a Shift Manager and a qualified reviewer signed off that the test results were satisfactory, that all data were in specification, and that all signature blocks and data blocks were completed or marked as N/A, and that all comments in the procedure were resolved.

On April 22, 1993, the inspector met with the Plant Manager to present these findings to the Supply System. As corrective actions, the Plant Manager assigned representatives of Operations, Electrical Maintenance and I&C to re-review these procedures without being prompted by a list of the NRC identified problems. The inspector met with each of the assigned reviewers prior to the end of the inspection period. These licensee reviewers also failed to identify several of the above listed concerns during the second review.

NRC Inspection Reports 92-01, 92-20, and 92-31 each identified numerous instances of procedure non-adherence. Following the identification of these problems, the licensee had conducted numerous training sessions, issued all-employee memoranda, and performed audits and surveillances of procedures to correct the procedure compliance problems at the Supply System. During a management meeting held between the NRC and the Supply System on March 4, 1993, licensee management stated that significant improvement had been made in the area of procedure compliance. The above findings, however, indicate that significant additional attention to procedure adherence is needed from licensee management. The above problems represent a violation of 10 CFR 50, Appendix B, Criterion V and TS 6.8.1 (Violation, 50-397/93-13-05).

One violation, with several examples, was identified.

7. 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 maintenance activities was correct.

The inspector witnessed portions of the following maintenance activities:

Description	Dates Performed
AP2973, Replace Fire Seals in the RHR C Pump Room	May 3, 1993

AP0737, Replace Control Rod Drive Hydraulic Control Unit (HCU) Accumulators	May 4-10, 1993
AP1993, Install Main Steam Line Plugs to Support Refueling	May 5, 1993

During observations of the work associated with replacement of the HCU accumulators, the mechanics had problems installing these units. The belly bands used to hold the accumulators in place appeared to be too small to fit around the new accumulators. This resulted in delays in installation of the new accumulators until this issue was resolved. The licensee found that the new accumulators had a diameter that was approximately 1/4-inch larger. However, the circumference of the new accumulator was within the adjustment band of the old belly bands and the work was resumed.

The mechanics (and the plant operators) noted another problem with the installation of the new accumulators. Each of the HCU units includes a drain and fill valve and a quick-disconnect fitting. In the old design, the drain valve and quick-disconnect had about 1/4-inch clearance from the old accumulators. However, upon installation of the newer larger accumulators, several of the quick-disconnect connections had no clearance from the accumulators and were actually hard against the accumulators. The licensee stated that modification of the quick-disconnect lines may be necessary to accommodate at least one of the quick-disconnects.

Because the licensee apparently was unaware of the potential installation difficulties until the work was in progress, the inspector questioned the planning process for the accumulator replacement. The inspector reviewed the documentation for planning the accumulator job and found that the licensee had treated the accumulator changeout as a like-for-like replacement rather than a design change. The inspector's further evaluation revealed that the new accumulators not only had a 1/4-inch larger diameter, but were made of stainless steel vice the old design of carbon steel, rated to 2100 psi vice the old design of 1750 psi, weighed slightly more, and used new adapters to connect them to the CRD piping. It appeared that if the licensee had treated this maintenance work as a design change, more thorough pre-planning and anticipation of interferences would probably have occurred.

PPM 1.4.1, "Plant Modification Records (PMR)," states that maintenance that involves a change in "fit, form, or function" of safety-related structures, systems, or components shall be treated as a PMR. The accumulator changeout work appeared to have changed the fit of the accumulators due to the effect on the quick-disconnects. The changes in material and pressure rating of the new accumulators also appeared to reflect a change (an improvement) in the "form". Technical Specification 6.5.1.6.d requires the Plant Operations Committee (POC) to review and approve all modifications and changes to safety-related systems. Because the Supply System considered the accumulator work to be a like-for-like substitution, it was not reviewed and approved by POC.

PPM 1.17.2, "Procurement Engineering Reviews," contains requirements for performing substitution evaluations. A "substitution" is defined as replacing an item with another item that was not completely identical but fulfills the design basis critical characteristics of the application, and therefore is considered equivalent. A substitution is not considered a design change. The only critical characteristic listed for the accumulator changeout was the vendor's part number. Thus, the licensee concluded that the accumulator changeout was a substitution and did not need the controls necessary for a PMR. At the exit of May 27, 1993, the PM reiterated that a second evaluation of this concern had been performed, with the conclusion that the designation as a substitute was correct.

The inspector will perform additional evaluation of the licensee's PMR and procurement engineering processes during a future inspection. Until then, the licensee's handling of the HCU accumulator changeout as a substitution is unresolved (Unresolved Item, 50-397/93-13-06).

No violations or deviations were identified.

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

The inspector reviewed the following LERs associated with operating events. 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.

89-06, Revision 1	"Entry Into TS 3.0.3 Caused By Discovery of Calculation Errors in Post LOCA Integrated Control Room Dose"
90-17, Revision 1	"High Pressure Core Spray System Inoperability as a Result of 125 VDC Battery Inoperability."

Revised LER 90-17 provided the results of the root cause analysis and an update of corrective actions for a licensee-identified event that reported three instances of inoperability of the HPCS system due to inoperability of the 125 VDC battery. The licensee concluded that the event had no effect on the public health and safety.

The inspectors discussed the corrective actions and root causes with licensee representatives. This LER is closed based on the licensee's proposed and implemented corrective actions. The inspectors noted that the corrective action to modify the HPCS battery rack is not planned for implementation until 1995. However, the LER concluded that there was no safety significance associated with this series of events, noting that the minor voltage variation (0.75 volts below the minimum required voltage of 129 volts) would not have impaired the battery's capability to perform its safety function.

No violations or deviations were identified.

9. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable items, violations, or deviations. Unresolved items addressed during this inspection are discussed in Paragraphs 5 and 7 of this report.

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 May 27, 1993. 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.