U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No: 50-397/90-31

Docket No: 50-397

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: December 3, 1990 - January 13, 1991

Inspectors: R. C. Sorensen, Senior Resident Inspector

C. D. Townsend, Resident Inspector (January 7 - 11)

Approved by: P H Johnson 2/12/91
P. H. Johnson, Chief Date Signed
Reactor Projects Section 3

Summary:

Inspection on December 3, 1990 - January 13, 1991 (50-397/90-31)

Areas Inspected: Routine inspection by the resident inspectors of control room operations, licensee action on previous inspection findings, operational safety verification, engineered safety feature (ESF) status, surveillance program, maintenance program, licensee event reports, special inspection topics, procedural adherence, and review of periodic reports. During this inspection, Inspection Procedures 61726, 62703, 71707, 71710, 90712, 90713, 92700, 92701 and 92702 were utilized.

Safety Issues Management System (SIMS) Items: None.

Results:

General Conclusions and Specific Findings

Significant Safety Matters: None.

Summary of Violations and Deviations: Two violations were identified involving (1) failure to take effective corrective actions to preclude repetition of the May 1990 diesel generator bearing failure and

(2) failure to comply with the Technical Specifications in the conduct of a required surveillance test. One deviation from a commitment was identified concerning resolution of high pressure core spray (HPCS) socket weld failures.

Strengths and Weaknesses: One weakness was identified involving compliance with the Technical Specification during the performance of a surveillance test (see paragraph 6), and another weakness was observed in the implementation of lessons learned from the June 1990 Emergency Diesel Generator bearing failure (see paragraph 4).

Open Items Summary:

Two unresolved items and seven LERs were closed; four new items were opened.

DETAILS

1. Persons Contacted

   *J. Baker, Plant Manager
   L. Harrold, Assistant Plant Manager
   C. Edwards, Quality Control Manager
   R. Graybeal, Health Physics and Chemistry Manager
   *J. Harmon, Maintenance Manager
   *A. Hosler, Licensing Manager
   *S. Davison, Quality Assurance Manager
   R. Koenigs, Generation Engineering Manager
   S. McKay, Operations Manager
   *J. Peters, Administrative Manager
   G. Gelhaus, Assistant Technical Manager
   *W. Shaeffer, Assistant Operations Manager
   R. Webring, Plant Technical Manager

   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 January 17, 1991.

2. Plant Status

   At the start of the inspection period, the plant was operating at 100% power. At about 10:10 a.m. on December 7, the reactor scrammed due to a short across a 500 KV insulator in the switchyard and the resultant 100% load rejection (see paragraph 10). The reactor was restarted on December 10 and reached 100% power by December 13, where it remained through 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. (Closed) Unresolved Item 397/90-28-01 - Recurrence of HPCS Socket Weld Failures in the Test Return Line

      The inspector reviewed a synopsis prepared by the licensee summarizing the history of high pressure core spray (HPCS) socket weld failures and explaining why they did not meet their commitment, as stated in Inspection Report No. 89-17, to assess the vibration problems in the HPCS test return line and correct these problems by the end of the 1990 refueling outage (R-5). The inspector noted that a plant modification had been designed and planned for implementation in 1991 to alleviate the vibration problem. However, it appears that no attempt was made to inform the NRC of the change in intent from that documented in Inspection Report No. 89-17, so that

a mutually agreeable resolution could have been achieved. Given the recurring nature of the socket weld failures in the HPCS system, and the importance of HPCS as an emergency core cooling system (ECCS), this would have been appropriate. Licensee management was advised that failure to fulfill a commitment as agreed to and documented in Inspection Report No. 89-17 is considered to be a deviation from a commitment to the NRC (Deviation 397/90-31-01). Unresolved Item 397/90-28-01 is closed.

b. <u>(Closed) Unresolved Item 397/90-28-04 - Determination of Stroke Time Requirements for RCIC-V-8</u>

This item had involved meeting a stroke time of 10 seconds for RCIC-V-8, a containment isolation valve. It had failed its stroke time criterion of 10 seconds, and during subsequent repair had its closed indication adjusted to 94% of full closed contrary to the MWR guidance of not less than 96% of full stroke closed. The stroke time was then measured to be less than 10 seconds and the valve was returned to an operable status. In reality, only the closed indication had been changed, not the stroke time. The licensee had written a nonconformance report (NCR) to document a Technical Specification (TS) violation. LER 90-30 also was issued to report a TS violation. This item was left unresolved in Inspection Report No. 90-28 pending further inspector review of stroke time requirements for the valve from a TS standpoint.

The inspector determined that the TS-required stroke time was 13 seconds. This value ensured an adequate containment isolation function for the valve. The value of 10 seconds was an FSAR commitment to ensure that environmental qualification of certain components in the reactor building was maintained in the event of a steam break in the reactor core isolation cooling (RCIC) steam supply line. Thus, the 10 second criterion was based on an equipment qualification concern, not containment isolation. The licensee carried out the instructions of the ASME Code in declaring the valve inoperable when the 10 second criterion was not met. The inspector will still follow the issue of deviating from MWR instructions, and potentially rendering valves inoperable as a result, when reviewing actions for LER 90-30.

This item is closed.

4. <u>Operational Safety Verification (71707)</u>

a. <u>Plant Tours</u>

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 Pumphouses
- Radwaste Control Room
- 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 that 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.

(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.

(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.

The inspector observed a number of minor discrepancies while touring the plant that indicated insufficient attention to detail. These issues, discussed at the exit meeting, included:

- A chemistry work cart was stored beside a safety related service water header with the cart clearly marked not to be left within 6 feet of any safety related equipment. The inspector notified chemistry personnel and the cart was relocated.

- A watertight door leading to the low pressure core spray (LPCS) pump room had been left open. The inspector closed the door and advised personnel working in the area.

- A technician working in a contaminated zone was observed to have his protective clothing improperly taped, while another worker was not wearing a hardhat outside the zone.

- Two reactor water cleanup (RWCU) system valves (RWCU-V-229B and V-234B), used to aid in backflushing the filter demineralizers, had remote handwheels with non-functional linkage systems. The linkages are provided to allow for remote operation, which would allow valve manipulation without entering the high radiation/contaminated zone. With the linkages inoperable, equipment operators had to dress in anti-contamination clothing and enter a high radiation area, incurring man-rem exposure each time these valves were manipulated. This condition had existed for some time and was not corrected before completion of this inspection. The inspector observed at the exit meeting that this issue presented an opportunity for the licensee to reduce man-rem exposure.

In addition, while the inspectors were examining the Division I Emergency Diesel Generator (EDG) on December 11, they observed the oil level in the north generator bearing sightglass to be approximately 1/8 inch below the low level mark. Further, there was a green deficiency tag attached, dated December 10, documenting this condition and indicating that the condition had existed for approximately 24 hours and perhaps longer with no corrective action. The inspector recalled that a similar condition in May of 1990 had caused failure of the north bearing, and eventually the south bearing, during a 24-hour run of the EDG, to the extent that the generator had to be shipped offsite for a lengthy period of time to effect repairs. The inspectors informed maintenance management and plant management concerning their observation on December 12.

Later, the inspector reviewed documentation which showed that oil had been added to the north bearing on two other occasions prior to December 10 -- once on November 3 and once on November 21, indicating that leaking oil from the north bearing had again become a problem. Similar precursors had occurred prior to the May 1990 failure. The licensee's root cause analysis for that failure had identified approximately 12 times when oil had been added to the north bearing prior to failure.

This recurring problem with generator bearing oil leakage presented the following concerns:

- Insufficient lessons learned from identical problems in the recent past. Conversations with members of the Plant Technical staff indicated that, as of December 11, there was still no formal method in place for the system engineer or another individual to track and trend oil additions to the EDG bearings. Oil additions to the generator bearings also were not being tracked in the EDG logbook. Numerous opportunities had presented themselves prior to the May 1990 event to allow correction of the leakage problem before catastrophic failure of the bearings. Although actions had apparently been taken in an effort to locate the cause of the leak prior to the 1990 bearing failure, these had been unsuccessful. That event demonstrated that the acceptable oil level band is very small, thus greatly increasing the need to closely monitor the level. Opportunities again presented themselves on November 3, November 21, and December 10, 1990, based on observations of bearing oil leakage, but action was apparently not taken to identify the cause or the extent of the leakage. Problem Evaluation Request (PER) 290-986, initiated to document the problem of oil additions in November and December, was not written until December 17, several days after the inspector had expressed his concern to plant management about the timeliness of oil addition to the EDG.

- Apparent insufficient sensitivity on the part of the plant staff to the significance of low bearing oil level in the

generator bearings. The deficiency tag observed on December 11 had been hanging for approximately a day with no action having taken place to correct the condition. Maintenance Work Request (MWR) AR 2023, initiated to correct the condition, was not released for work until dayshift on December 12, over two days after the deficiency tag was hung (it had been dispositioned as Priority 2). Further, MWR AR 1476, initiated to correct the condition identified on November 1, was not released for work until dayshift on November 3, a period of two days. MWR AR 1761, initiated to correct the condition identified at 1:00 a.m. on November 21, was more timely; however, it was not released for work until swingshift on November 21. Given the close tolerances of the sightglass level marks, and the unforgiving nature of the lubrication requirements for the thrust bearing, more timely action would appear to have been warranted. Conversations with cognizant members of the Plant Technical staff indicated that this had originally been intended when guidance on the monitoring of EDG bearing oil levels was provided to Plant Operations by a memorandum in August 1990.

- Lack of timeliness in establishing the bearing oil level at which the EDG should be declared inoperable. Plant Technical had provided no guidance on this topic in their August 1990 memorandum to Plant Operations, assuming instead that prompt action would be taken to correct any low level problem identified. Guidelines included in PPM 2.7.2, "Emergency Standby AC Generator", indicated that a level less than the low level mark in the sightglass was considered a low level, implying that the EDG was not to be started until it was corrected.

Near the end of the inspection period, the licensee initiated action to determine the cause of the oil leak, monitor the leakage at frequent intervals, and establish guidelines for inoperability. However, repair of the leak was postponed until the R-6 outage, and guidance regarding inoperability had not been included in the EDG operating procedure (PPM 2.7.2) as of the end of the inspection period. The licensee's failure to implement appropriate corrective actions in response to the May 1990 bearing failure -- specifically, to establish clear acceptance criteria for acceptable bearing oil level and to ensure proper monitoring of bearing oil leakage and oil additions -- is considered to be a violation of the corrective action requirements of 10 CFR 50, Appendix B, Criterion XVI (Violation 90-31-02).

c. <u>Safety System Walkdowns</u>

Selected engineered safety feature systems (and systems important to safety) were walked down by the inspectors to confirm that the systems were aligned in accordance with plant procedures. During the walkdown of the systems, items such as lubrication of major components and cooling water/ventilation were inspected to

determine that they were operable and in a condition to perform their required functions. The inspectors also verified that the 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
Scram Discharge Volume System	December 13
Standby Service Water System	January 11
125V DC Electrical Distribution, Divisions 1 and 2	January 2
250V DC Electrical Distribution	January 2

No violations or deviations were identified.

5. Engineered Safety Feature System Walkdown (71710)

a. The inspector verified the accessible portions of the Low Pressure Core Spray (LPCS) system alignment utilizing the system operating procedure, PPM 2.4.3, "Low Pressure Core Spray System," and the flow diagram, drawing M520, "Flow Diagram, HPCS and LPCS Systems, Reactor Building." The inspector observed that the system was aligned correctly according to current plant documentation, with the exception that the test return line maintenance block valve, LPCS-V-60, was identified on the drawing as locked open and the actual condition was open but not locked. The inspector reviewed the locked valve checklist and determined that the valve was no longer required to be locked, but that the drawing had not been updated to reflect the change. Additionally, the inspector observed that the watertight door to the LPCS pump room was not secured as required and that the scaffolding leading to valve LPCS-V-60 was labeled as OSHA qualified, but was not secured. Specifically, one of the lug nuts used to secure the ladder to the scaffolding was missing and another was not tight, rendering the ladder unstable. This was communicated to the Shift Manager, who took action to correct it.

b. The inspectors also conducted a walkdown of accessible portions of the High Pressure Core Spray (HPCS) system, verifying system alignment in accordance with the system operating procedure, PPM 2.4.4, "High Pressure Core Spray System," and the flow diagram, drawing M520. The inspector noted that the system was correctly aligned. However, a number of deficiencies were noted as follows:

- Several vent and drain valves were missing handwheels. Handwheels were loose in other instances.

- HPCS-V-20, an air operated sample valve, could not be located on either the valve checklist from PPM 2.4.4, or drawing M520.

- HPCS-V-711 had no label plate. Likewise, a drain valve downstream of HPCS-V-11 had no label plate.

- HPCS-V-64, suppression pool test return block valve, was noted to be locked open, and was shown locked open on the drawing, but not included on the locked valve checklist from PPM 2.4.4. Review of the locked valve checklist indicated that the valve was not required to be locked.

Other aspects of the HPCS system, such as hangers and supports, housekeeping, freeze protection, fire protection, lubrication and cooling, were examined to ensure operability of the system.

No violations or deviations were identified.

6. 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 surveillance test procedure existed which met the surveillance requirements of the TS; (2) the surveillance tests had been performed at the frequency specified in the TS; 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
7.4.4.1.2	Jet Pump Operability	January 9
7.4.3.1.1.5.0	RPS and Isolation Reactor Vessel Level Low, Level 3; RCIC Isolation, Level 8-CFT/CC	January 9

During the inspection of the RCIC surveillance, the inspector observed that the test technician inside the contaminated area did not properly don the anti-contamination clothing in two places, both of which were corrected by re-taping. Also, the test technician outside of the contaminated area was not wearing a hardhat as required by plant industrial safety rules.

While reviewing the above jet pump operability surveillance, the inspector noted that the TS required the testing to be performed with both recirculation loops operating at the same flow control valve (FCV) position. However, the licensee was performing the test on January 9 with loop flows balanced, and stated that they typically ran the surveillance test in this manner. Having loop flows balanced does not necessarily mean that FCVs are in the same position, as required by TS. This was the case on January 9, when the FCV in loop "A" was at 88.8% and the loop "B" FCV was at 84.6%. This is considered to be a violation of the TS, Section 4.4.1.2.1 (Violation 397/90-31-03). After further research, the inspector noted that Revision 0 to PPM 7.4.4.1.2, dated October 27, 1983, was originally written correctly to comply with the surveillance requirement to match FCV position. However, a deviation was written to the procedure on January 18, 1985, that was later approved by the Plant Operations Committee on January 30, providing new instructions to match recirculation loop flows, apparently without sufficient regard for the TS requirements. It therefore appeared to the inspector that this surveillance test had been performed in violation of TS requirements since January, 1985. After this violation was identified, the licensee successfully repeated the surveillance test with FCV positions matched (as required by the TS), and concluded that jet pump operability had not been affected. The licensee also stated that the apparent intent of the specification was to require loop flow to be balanced during the surveillance test, and was considering a TS change request to that effect.

7. Plant Maintenance (62703)

During the inspection period, the inspectors 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 inspectors verified that reportability for these activities was correct.

The inspectors witnessed portions of the following maintenance activities:

Description	Dates Performed
MWR AS-5393, Fuel Pool NW Jib Crane, MT-CRA-9A, Appears To Be Mechanically Bound, Preventing Boom Extension And Retraction	January 11

No violations or deviations were identified.

8. Cold Weather Preparations (71714)

The inspector reviewed PPM 1.3.37, "Cold Weather Operations," and observed several areas in and around the plant to verify that proper freeze protection was in place. Specific areas examined were the standby service water pumphouses, condensate storage tank pit, and circulating water pumphouse. Unit heaters were examined for operability as applicable, and heat trace panels were examined to ensure that the proper light bulbs were lighted and no low temperature alarms existed.

The inspector found the licensee's cold weather preparations to be adequate to preclude the freezing of safety-related or important-to-safety systems or components. However, the inspector identified the following:

- Heaters for the condensate storage tank (CST) are powered from non-Class 1E power supplies. This could potentially be a problem in a loss of offsite power situation during cold weather. The inspector noted that other non-critical components around the plant, such as air wash pumps for the reactor building heating, ventilation, and air conditioning (HVAC), were provided Class 1E power.

- PPM 1.3 37, section 4.C.3 states: "Ensure there is no debris in CST pit area that could plug the drain and flood." However, the drain apparently was plugged because several inches of water were observed in the CST pit area, such that the heat trace panel could only be observed from a distance without using boots.

- Heat trace panels were being checked once a day by equipment operators. Section 3 of PPM 1.3.37 stated that these panels should be checked by each shift when they are in service during cold weather.

- One circuit on the heat trace panel in the CST area had a low temperature alarm, even though ambient temperature was above the alarm point of 35 degrees at the time.

While the above observations did not appear to adversely affect safety or system operability, they indicated program weaknesses and were communicated to plant management for followup (Followup Item 397/90-31-04).

No violations or deviations were identified.

9. <u>Licensee Event Report (LER) Followup (90712, 92700)</u>

The following LERs associated with operating events were 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 LERs are considered closed.

LER NUMBER	DESCRIPTION
90-24	Emergency Diesel Generator Start on Undervoltage due to Grid Disturbance
90-25	Inoperability of HPCS due to Equipment Failure
90-27	Diesel Fuel Oil not Tested for Sulfur Content
90-28	Degradation of Containment Pressure Boundary due to Cracks in the HPCS System

90-29	Inadequate Containment Penetration Testing on Wetwell Hatch Pressure Warning Devices
90-31	Reactor Scram Due to Shorted 500 KV Insulator
90-32	Unanalyzed Secondary Leakage Path Through Sanitary Drain Piping

No violations or deviations were identified.

10. 500 KV Insulator Failure and Resultant Reactor Scram (93702)

At approximately 10:10 a.m. on December 7, 1990, a fault to ground occurred on an insulator associated with the "B" phase on the output of the main transformer. This led to actuation of main transformer lockout relays with a resultant 100% load rejection, turbine trip and reactor scram. Both standby EDGs started, as designed, due to the voltage transient on the vital AC busses. The HPCS EDG was already running because of a surveillance test in progress. An Unusual Event was declared, but was terminated at about 11:00 a.m. after plant conditions were stabilized. Reactor pressure vessel (RPV) level decreased to approximately -7 inches and one safety relief valve lifted for approximately 10 seconds. RPV level subsequently increased to the Level 8 setpoint, in spite of operator action to prevent it, tripping both reactor feedwater pumps. Operators were successful in restoring one feed pump to operation within a few minutes to supply makeup water. The plant was taken to cold shutdown later that evening.

The cause for the insulator failure was determined by the licensee to be the buildup of deposits from cooling tower drift, thereby providing a path for a fault to ground across the surface of the insulator. This event had occurred once before (see inspection report 89-04). The licensee had instituted a semi-annual preventive maintenance (PM) action to clean insulators on the 500 KV lines, as well as the 230 KV and 115 KV lines. However, in the interest of personnel safety, they could only be cleaned with the lines deenergized and thus the 500 KV lines had not been cleaned since the refueling outage in May 1990. This frequency of cleaning was apparently not sufficient for the weather and cooling tower conditions being experienced.

Bonneville Power Administration personnel cleaned the 500 KV insulators from the main transformers to the Ashe substation. The 230 KV and the 115 KV insulators were also cleaned to a considerable distance from the the plant switchyard. The inspector observed some of the cleaning activities. The inspector also attended the licensee's Restart Decision Committee meeting which reviewed the scram and the root causes thereof, and established corrective actions. Interim corrective actions that the Committee proposed were as follows:

- Decreasing the cycles of concentration of circulating water from about twelve cycles to five. This should effectively reduce the concentration of salts in the circulating water, which would reduce

the concentration of salts entrained in the cooling tower plume and thus reduce salt deposition on the insulators.

- Decreasing the Calgon concentration in the circulating water from about 90 PPM to about 50-60 PPM. Calgon is added to keep solids suspended in solution to prevent plateout in the tubes of various heat exchangers. However, when deposited on the insulators, it also tends to enhance the loss of insulating properties during high moisture weather conditions.

- Decreasing the addition to the circulating water of certain other additives, used to enhance the Calgon properties, but which tend to aggravate the loss of insulation properties when deposited on the insulators.

- Establishing a monitoring program for the insulators in an attempt to predict when cleaning will be necessary.

- Varying the number of cooling tower fans in operation during certain windy weather conditions.

Since none of these actions would preclude the need for periodically cleaning the insulators, long term corrective actions under consideration by the licensee were as follows:

- Installation of drift eliminators in the cooling towers.

- Installation of creep extenders on the insulators. This would effectively increase the distance that a potential short to ground would have to traverse and thus decrease its likelihood of occurring.

- Installation of circuitry that would preclude RPV level reaching the Level 8 trip setpoint (and causing a trip of the feedwater pumps), even following a 100% load rejection transient.

No violations or deviations were identified.

11. <u>Review of Periodic and Special Reports (90713)</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, and the reported information appeared valid. Within the scope of the above, the following report was reviewed by the inspector.

- Monthly Operating Report for November, 1990.

No violations or deviations were identified.

12. 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 paragraph 3 of this report.

13. Exit Meeting

The Senior Resident Inspector 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 January 17, 1991. An exit meeting was also conducted at the conclusion of Mr. Townsend's inspection on January 11. 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 inspector during the inspection.