U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No. 50-344/85-39

Docket No. 50-344 License No. NPF-1

Licensee: Portland General Electric Company
121 S. W. Salmon Street
Portland, Oregon 97204

Facility Name: Trojan

Inspection at: Rainier, Oregon

Inspection conducted: November 17, 1985 - January 3, 1986

Inspectors: J. L. Burdoin FOR 1/24/86
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Senior Resident Inspector

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R. T. Dodds, Chief Date Signed
Reactor Projects Section 1

Summary:

Inspection on November 17, 1985 - January 3, 1986 (Report 50-344/85-39)

Areas Inspected: Routine inspection of operational safety verification, corrective action, maintenance, surveillance, followup on a reported potential act of sabotage, review of modification testing, and inspection of various aspects of plant operation. The inspection involved 212 inspector-hours by the NRC Resident Inspectors. 35 hours of inspection were during back shift hours. Inspection procedures 30703, 40700, 61726, 62703, 71707, 71710, 72701, 93702 and 94703 were used as guidance during the conduct of the inspection.

Results: No violations or deviations were identified.

DETAILS

1. Persons Contacted

*W.S. Orser, Plant General Manager
*R.P. Schmitt, Manager, Operations and Maintenance
*D.R. Keuter, Manager, Technical Services
J.D. Reid, Manager, Plant Services
R.E. Susee, Operations Supervisor
D.W. Swan, Maintenance Supervisor
A.S. Cohlmeyer, Engineering Supervisor
G.L. Rich, Chemistry Supervisor
T.O. Meek, Radiation Protection Supervisor
S.B. Nichols, Training Supervisor
D.L. Bennett, Control and Electrical Supervisor
M.R. Snook, Acting Quality Assurance Supervisor
R.W. Ritschard, Security Supervisor
H.E. Rosenbach, Material Control Supervisor
J.K. Aldersebaes, Manager, Nuclear Maint. and Construction

The inspectors also interviewed and talked with other licensee employees during the course of the inspection. These included shift supervisors, reactor and auxiliary operators, maintenance personnel, plant technicians and engineers, and quality assurance personnel.

*Denotes those attending the exit interview.

2. Operational Safety Verification

During this inspection period, the inspectors observed and examined activities to verify the operational safety of the licensee's facility. The observations and examinations of those activities were conducted on a daily, weekly, or biweekly basis.

On a daily basis, the inspectors observed control room activities to verify the licensee's adherence to limiting conditions for operations as prescribed in the facility technical specifications. Logs, instrumentation, recorder traces, and other operational records were examined to obtain information on plant conditions, trends, and compliance with regulations. On occasions when a shift turnover was in progress, the turnover of information on plant status was observed to determine that all pertinent information was relayed to the oncoming shift.

During each week, the inspectors toured the accessible areas of the facility to observe the following items:

a. General plant and equipment conditions.
b. Maintenance requests and repairs.
c. Fire hazards and fire fighting equipment.
d. Ignition sources and flammable material control.

e. Conduct of activities in accordance with the licensee's administrative controls and approved procedures.
f. Interiors of electrical and control panels.
g. Implementation of the licensee's physical security plan.
h. Radiation protection controls.
i. Plant housekeeping and cleanliness.
j. Radioactive waste systems.

The licensee's equipment clearance control was examined weekly by the inspectors to determine that the licensee complied with technical specification limiting conditions for operation with respect to removal of equipment from service. Active clearances were spot-checked to ensure that their issuance was consistent with plant status and maintenance evolutions.

During each week, the inspectors conversed with operators in the control room, and with other plant personnel. The discussions centered on pertinent topics relating to general plant conditions, procedures, security, training, and other topics aligned with the work activities involved.

The inspectors examined the licensee's nonconformance reports (NCR) to confirm that deficiencies were identified and tracked by the system. Identified nonconformances were being tracked and followed to the completion of corrective action. NCRs reviewed during this inspection period included P85-40, P85-47, and P85-63.

Logs of jumpers, bypasses, caution, and test tags were examined by the inspectors. Implementation of radiation protection controls was verified by observing portions of area surveys being performed, when possible, and by examining radiation work permits currently in effect to see that prescribed clothing and instrumentation were available and used. Radiation protection instruments were also examined to verify operability and calibration status.

The inspectors verified the operability of selected engineered safety features. This was done by direct visual verification of the correct position of valves, availability of power, cooling water supply, system integrity and general condition of equipment, as applicable. ESF systems verified operable during this inspection period included the spent fuel pool cooling system, diesel fuel oil system, containment spray system, the auxiliary feedwater system, and the safety injection system.

No violations or deviations were identified.

3. Corrective Action

The inspectors performed a general review of the licensee's problem identification systems to verify that licensee identified quality related deficiencies are being tracked and reported to cognizant management for resolution. Types of records examined by the inspectors included Requests for Evaluation, Event Reports, Plant Review Board meeting minutes, and Quality Assurance Program Nonconformance Reports. The inspectors concluded that the licensee's systems were being utilized to

correct identified deficiencies. Plant Review Board meetings were attended by the inspectors on December 11 and January 2. The inspectors verified that the appropriate committee members were present at the meeting and that the meeting was conducted in accordance with the requirements of section 6.5.1 of the facility technical specifications.

No violations or deviations were identified.

4. Maintenance

A maintenance activity observed during this inspection period was the calibration of the internal drawer modules of the N41 channel of the power range nuclear instrumentation on December 19. During this activity, the inspectors verified that the personnel performing the activity were qualified, that the appropriate procedure was followed, and that the equipment was removed from and restored to service in a manner allowed by the technical specifications. The inspector also verified that the appropriate administrative procedures were followed in conducting the calibration. The inspectors also observed that the test equipment was indicated to be in calibration and data were properly recorded by the technicians when required by procedure.

No violations or deviations were identified.

5. Surveillance

The surveillance testing of safety-related systems was witnessed by the inspectors. Observations by the inspectors included verification that proper procedures were used, test instrumentation was calibrated and that the system or component being tested was properly removed from service if required by the test procedure. Following completion of the surveillance tests, the inspectors verified that the test results met the acceptance criteria of the technical specifications and were reviewed by cognizant licensee personnel. No corrective action was required due to the test results. The systems were returned an operable status consistent with the technical specification requirements following the completion of the test. Surveillance tests witnessed during the inspection period were associated with a full core flux map on December 5, safety injection pump inservice testing on December 18, and incore/excore nuclear instrumentation calibration on January 3.

No violations or deviations were identified.

6. Modification Testing

The inspectors reviewed the documentation of testing performed for four modifications which were implemented during the 1985 outage. The modifications, designated by the licensee as Requests for Design Change (RDC), are as follows:

- RDC 83-042, which implemented shunt trip attachments on the reactor trip breakers.

- RDC 83-051, which modified the function of the boron injection tank such that heat tracing and recirculation of the tank contents is no longer required.

- RDC 83-054, which installed environmentally qualified electrical connections on the reactor head vent valves and the hydrogen analyzer containment isolation valves.

- RDC 83-059, which replaced the limit switches on two chilled water containment isolation valves with environmentally qualified switches.

The inspectors verified that the testing conducted checked the modification for proper operation and that the completed test results were properly reviewed and filed for document retention. The inspectors concluded that the testing for the four modifications reviewed was adequate. The inspectors did observe that testing requirements for modifications are not always clearly stated in the modification packages. This concern was previously noted by the licensee's quality assurance organization and is being acted on by the licensee.

No violations or deviations were identified.

7. Technical Review Meeting

As discussed in inspection report 85-21, the number of engineering discrepancies noted during the past 18 months had caused the inspectors to question the adequacy of licensee's reviews of technical work. On December 13, 1985, the licensee met with several representatives of the NRC, at the licensee's corporate office, to discuss actions underway to improve their performance in this area. These actions are summarized as follows:

- Additional resources are being provided to the nuclear division. Twenty-nine new positions have been approved for 1986 and 42 temporary or contract positions will be made permanent.

- Design change and calculational procedures have been or are being revised to eliminate the source of past errors.

- Programs are underway to update and reverify vendor manuals and electrical vendor drawings.

- Specific problem areas, such as safety related tank volumes being in error, are receiving detailed engineering reviews.

- The licensee's management has initiated several actions to more closely control and monitor activities in this area.

The NRC representatives discussed the importance of ensuring that strong independent technical reviews are being performed by personnel in the nuclear division. They also stressed the need for management to encourage a questioning attitude in their personnel and to reinforce that atmosphere by frequent personal contact with workers at the site. The

NRC representatives concluded that the actions taken by the licensee are a positive step towards minimizing errors in technical work.

No violations or deviations were identified.

8. Shift Crew Manning

The inspectors reviewed the information associated with the Possible Reportable Occurrence (PRO) report dated June 25, 1985. This PRO concerns potentially inadequate shift crew manning on the day shift of June 25, 1985. On this date, the plant was in Mode 5 and in a solid plant condition. Technical Specification 6.2.2 and Administrative Orders 1-4, 3-1 and 3-8 require a minimum shift crew of six operators in Mode 5. In addition, Administrative Order 3-8 requires that during solid plant operations, one operator will monitor RCS parameters and have no other concurrent duties.

The inspectors discussed this event with the initiator of the PRO and with the Operations Planner/Scheduler. Based on these discussions and review of the associated records, the inspectors determined that the shift was adequately manned. The inspectors did, however, question the lack of firm criteria for determining the availability of fire brigade members for response to a fire. In this instance, one of the fire brigade members was inside the containment building for a portion of the shift, and his ability to respond to a fire in the uncontrolled areas of the plant in a timely manner was in question. The Operations Planner/Scheduler agreed to investigate this issue to determine if additional guidance on fire brigade member availability is necessary. This issue will be followed up in a future inspection (344/85-39-01).

9. Potential Sabotage Event

On December 9, 1985, while in the process of performing a semi-annual preventative maintenance inspection on the 'A' emergency diesel generator (EDG), a licensee mechanic discovered an 8 ounce ball-peen hammer under a rocker-arm cover on the east unit of the EDG. The engine was operating at the time and the worker immediately removed the hammer from the engine. The hammer had not caused any damage to the engine. Its location was such that the probability for damage to occur should the hammer have shifted its position due to engine vibration appeared very low. The licensee initially thought that the hammer had been inadvertently left in the engine by a maintenance worker, however, a review of maintenance records indicated that during the time frame in question, no work had been performed on the engine which could account for the hammer. Because the licensee was unable to determine how the hammer came to be placed in the engine, the licensee reported the event to the NRC and the FBI as a potential act of sabotage.

A special agent from the Portland office of the FBI commenced an investigation into the circumstances surrounding this event. The licensee initiated action to survey the plant for other evidence of tampering. These actions included detailed visual examinations of electrical panels, rotating equipment, and other selected vital equipment; sampling of oil from selected safety equipment; a visual

examination of the 'B' EDG rocker arm assemblies; extensive plant wide tours by operations personnel looking for out-of-normal conditions; and verification of the locked valves in the EDG and auxiliary feedwater systems. No other evidence of tampering was found.

The inspectors reviewed the licensee's actions with plant management and closely followed the licensee's efforts to survey the plant. The inspectors also independently reviewed maintenance records associated with the EDG. The Plant Review Board (PRB) met and discussed the event and the actions being taken. Because no further evidence of tampering was found, the PRB recommended to plant management that no further action be taken pending the completion of the FBI investigation. At the conclusion of the inspection period, the FBI investigation remained open. The licensee's security organization is also reviewing this event. The inspectors concluded that the licensee response to this event, to date, has been appropriate. Licensee management stated that the resident inspectors will be kept informed of any further developments.

No violations or deviations were identified.

10. Miscellaneous Observations

During a routine control room tour, the inspectors noted that component cooling water (CCW) flow had been secured to the B-2 and B-3 containment air coolers (CAC) in an effort to increase CCW flow to the excess letdown heat exchanger, which was then in service. The inspectors questioned whether the operability of the CACs was affected by this condition, however, the control operator indicated that the CACs could still be considered operable with CCW flow secured. After a review of technical specification requirements, the personnel on shift agreed that CCW flow to the CACs was required to consider them operable. A technical specification violation did not occur due to the short period of time that the system was in this condition. Based on discussions with other operations personnel, the inspectors concluded that this was an isolated weakness in the individual operator's knowledge. The inspectors discussed this occurrence with the plant general manager.

Because of the recent removal of the boron injection tank from the service for which it was originally designed, valves MO 8803 A/B have been placed in the open position with power to the valve operators removed. This also deactivated the valve position indication in the control room. These valves are in the direct flow path of the high pressure injection pumps and as presently aligned are basically manual valves. The inspectors questioned whether they should be designated as locked valves. The licensee is considering this concern.

The licensee has continued to experience an increasing primary to secondary leak in the 'C' steam generator. At the close of the inspection period, the leak rate was approximately 140 gallons per day. The licensee has taken action to increase health physics monitoring of secondary plant systems. The inspectors will follow the licensee's actions to monitor the leak closely.

No violations or deviations were identified.

11. Inservice Testing of Snubbers

The results of the licensee's inservice testing of snubbers in conformance to technical specification requirements during the 1985 refueling outage was examined by a review of test and maintenance data and discussions with responsible engineers. The testing was performed pursuant to procedure number 0816N.0185, Snubber Inservice Test Program. All changes to test acceptance criteria and/or deviations had been properly reviewed and approved by the Plant Review Board and the General Manager.

The licensee determined that a high percentage of PSA-1/4 and PSA-1/2 mechanical snubbers manufactured by Pacific Scientific were inoperable. The cause of these failures has not yet been determined. Additionally, hydraulic snubbers manufactured by both Anker-Holth and Bergen-Paterson were found significantly degraded, primarily due to deteriorated seals. The inoperable mechanical snubbers were replaced with operable mechanical snubbers, and the hydraulic snubbers were rebuilt and retested satisfactorily.

All of the mechanical pipe snubbers at Trojan were manufactured by Pacific Scientific. An initial sample of 10 percent of each type of mechanical snubber ranging from PSA-1/4 to PSA-35 was tested. Each snubber was evaluated for operability based on predetermined acceptance criteria established for Trojan on the basis of manufacturer's acceptance criteria and generalized stress analyses. Each snubber which failed the predetermined acceptance criteria was declared inoperable and an additional 10 percent of that type of snubber was tested. As a result of high failure rates, 100 percent of the PSA-1/4s and PSA-1/2s were functionally tested. The following table displays for each type of mechanical snubber, the number tested, the percent of the total of that type which were tested, and the number of failures. Several snubbers which did not meet the predetermined acceptance criteria were later declared operable when a specific stress analysis for the particular installation was performed. The table represents the final failure total.

Snubber Type	No. Tested	Percent of Total	No. of Failures
PSA-1/4	50	100	13
PSA-1/2	74	100	12
PSA-1	8	20	0
PSA-3	11	10	0
PSA-10	10	10	0
PSA-35	2	10	0

The cause of some of the failures (22) was attributed to exceeding the 5-percent drag force criterion. The failure mechanisms for the snubbers was still being evaluated by the licensee and the manufacturer.

There are four 900-kip, Anker-Holth hydraulic snubbers installed on each of Trojan's four steam generators. During the 1985 refueling outage, all 16 snubbers were visually inspected with no significant discrepancies noted. Paul-Munroe Incorporated, was contracted to perform the

functional testing of these snubbers. The first two snubbers tested (from the D steam generator) would not respond under a 100-kip load. The snubbers appeared to be locked in a cold position (i.e., fully compressed). As a result of these test failures, and in light of the uncertainty regarding the time required to rebuild the snubbers, a decision was made to assume all the steam generator snubbers were inoperable, and not perform any further testing. The snubbers were then removed and overhauled by Paul-Munroe. During the overhaul of the snubbers, marks were found on the cylinder walls indicating the snubbers had been moving. The snubber seals were found to be degraded and the hydraulic fluid was heavily contaminated with seal material and rust. Paul-Munroe was of the opinion that the foreign material in the hydraulic fluid would not have affected the normal operation of the snubbers because of the relatively large channels through which the fluid would normally flow. In the case of a seismic or other severe dynamic event, it was determined the snubbers would have locked up but that the foreign material could have blocked the bleed orifice, thereby preventing the snubber from unlocking. There have been no seismic or other severe dynamic events at Trojan which would have caused the snubbers to lock up. This was further evidenced by the fact the seals showed no signs (e.g., extrusion) of having been under a large load.

Following overhaul, the snubbers were retested using the criteria in Section 5.4.12.1.7 of the Trojan Updated Final Safety Analysis Report; namely the snubbers maximum drag force is 1,000 lbs. at a minimum displacement rate of 25 mil/min. The snubbers could not satisfy these criteria. Each time the snubber velocity approached 25 mil/min., the snubber locked up. Through correspondence with Westinghouse (the NSSS), the acceptance criteria were revised to a minimum displacement rate of 7.6 mil/min with a maximum drag force of 5,000 lbs. The snubbers tested satisfactorily with these criteria.

There are four hydraulic pipe snubbers installed on safety-related piping at Trojan. These snubbers were manufactured by Bergen-Paterson, and are installed on the four main steam lines inside Containment. The snubbers installed on the A and B main steam lines are rated at 130 kip, and those installed on the C and D main steam lines are rated at 70 kip. Each of these snubbers was visually inspected and functionally tested.

Due to the problems encountered during the functional testing of the first two steam generator hydraulic snubbers, all four main steam line snubbers were declared inoperable and sent offsite to be rebuilt before being tested. Two were found to have physical defects which would have prevented them from performing their intended function. One snubber had a damaged reservoir, which was found by visual inspection. The second snubber had a compression side poppet and spring installed backwards and would only have been able to carry load in the tension direction. The seals in all of the snubbers were found degraded. This degradation alone would not have caused the snubbers to restrict thermal growth, but would have affected the capability of the snubbers under severe dynamic or seismic events. Following overhaul, the snubbers tested satisfactorily.

At the time of the inspection the licensee was still evaluating the effects of the failed snubbers on system components. The analysis had

apparently only been underway for about a month and appeared to have been prompted by an inquiry from plant engineering to downtown engineering. The need to perform this analysis required by the technical specifications had not been identified as an open item on any of the licensee's tracking systems. The results of the licensee's investigation will be furnished to the NRC as a special report, according to the licensee.

Preliminary analysis indicated that the piping had not been affected by the failed mechanical snubbers.

As a separate issue, the licensee has been monitoring unusual pipe movements of the pressurizer surge line since 1982. A walkdown of this line at the beginning of the 1985 refueling outage revealed additional movement had occurred. A consultant was hired to evaluate and analyze the movements of the pressurizer surge line. The consultant analyzed various potential causes of the observed movement. It was determined that none of the potential causes, either alone or combined, could have produced the forces required to result in the observed movement. The consultant was advised that some problems had been encountered in testing the steam generator snubbers. The licensee directed the consultant to analyze the surge line movements using the worst-case assumption that the snubbers may have been locked. The preliminary analyses, which were completed in November 1985, revealed that locked-up snubbers could have produced the movement necessary to displace the surge line as observed.

Based on this finding, further worst-case analyses of reactor coolant loop thermal expansion with locked-up snubbers was to be performed to demonstrate the structural integrity of the Reactor Coolant System (RCS), and its associated supports. The analyses was to be performed under the rules of Subsection NB-3600 of Section III of the ASME Boiler and Pressure Vessel Code. The licensee subsequently stated that the worst-case analysis was on the B reactor coolant loop and revealed the stress at the elbow where the B RCS hot leg enters the B steam generator would be in excess of the yield stress for the material. Subsequently, a plastic analysis was performed for this elbow in accordance with Subsection NB-3228 of Section III, with strain acceptance criteria as specified in Appendix T of Code Case N47. This analysis revealed the strain in the elbow due to thermal expansion loads would be less than the one percent limit specified in Appendix T of Code Case N47. The fatigue usage factor was determined to be less than 0.1 based on 30 heatup/cooldown cycles.

This work will be followed up as open item 85-39-02.

11. Exit Interview

The inspectors met with the plant general manager and members of his staff at the conclusion of the inspection period. During this meeting, the inspectors summarized the scope and findings of the inspection.