U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No. 50-344/89-20

Docket No. 50-344

License No. NPF-1

Licensee: Portland General Electric Company
121 S.W. Salmon Street, TB-17
Portland, OR 97204

Facility Name: Trojan

Inspection at: Rainier, Oregon

Inspection conducted: July 30, 1989 - September 9, 1989

Inspectors: R. C. Barr
Senior Resident Inspector

J. F. Melfi
Resident Inspector

Approved By: M. M. Mendonca 9/29/89
M. M. Mendonca, Chief
Reactor Projects Section 1
Date Signed

Summary:

Inspection on July 30 - September 9, 1989 (Report 50-344/89-20)

Areas Inspected: Routine inspection of operational safety verification, maintenance, surveillance, event follow-up, system engineering, and open item follow-up. Inspection procedures 30702, 30703, 61726, 62703, 71707, 92700, 92701, and 93702 were used as guidance during the conduct of the inspection.

Results

This inspection identified three apparent violations of regulatory requirements. Weaknesses included (1) failure to implement adequate administrative controls to ensure compliance with technical specification surveillance requirements; and (2) failure to acceptably store quality records in a timely manner (non-cited violation).

Additionally, throughout this inspection period there were numerous repetitive failures of electronic safety equipment. The failures appear to be due to a combination of component failure, poor workmanship, and inadequate quality verification. The inability to arrest these repetitive equipment failures appear to be due in part to management's willingness to continue operation with lingering deficiencies.

Finally, an unresolved item relating to Final Safety Analysis Report seismic design analysis was identified.

DETAILS

1. Persons Contacted

 D. W. Cockfield, Vice President, Nuclear
*C. P. Yundt, Plant General Manager
*T. D. Walt, General Manager, Technical Functions
 R. M. Nelson, Manager, Nuclear Safety and Regulation Department
 A. N. Roller, Manager, Nuclear Plant Engineering
 C. K. Seaman, Manager, Nuclear Quality Assurance
*D. W. Swan, Manager, Technical Services
*M. J. Singh, Manager, Plant Modifications
*J. D. Reid, Manager, Quality Support Services
*J. W. Lentsch, Manager, Personnel Protection
 J. M. Anderson, Manager, Material Services
*R. E. Susee, Manager, Work Planning and Control
*D. L. Bennett, Branch Manager, Maintenance
 J. Mody, Branch Manager, Plant Systems Engineering
 D. L. Nordstrom, Branch Manager, Quality Operations
*J. P. Fischer, PM/EA Branch Manager
 T. O. Meek, Branch Manager, Radiation Protection
 R. N. Prewit, Supervisor, Quality Systems
 D. F. Levin, Supervisor, Plant Modifications
*E. A. Curtis, Procurement Supervisor
*R. L Russell, Operations Supervisor
 J. C. Heitzman, Acting Assistant Operations Supervisor
 D. L. Bennett, Maintenance Supervisor
 N. A. Regoli, Instrument and Control Supervisor
 J. A. Benjamin, Supervisor, Quality Audits
 J. D. Guberski, Nuclear Safety and Regulation Department Engineer
*W. J. Williams, Compliance Engineer

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. Plant Status

On July 30, 1989, the facility was in Mode 3, Hot Standby, at normal operating temperature and pressure with an investigation in progress as to the cause of blown fuses for rod D-4 that had dropped from 105 steps withdrawn on July 27, 1989. At 5:22 pm, on July 31, 1989, after determining that the rod D-4 blown fuses resulted from low resistance grounds in containment electrical penetration NZ13 and correcting the problem, the reactor was restarted. At 6:28 pm, the reactor was again shutdown when control rod K-14 misaligned by twenty-four steps from the remainder of the control rods in its control bank. At 5:22 am, August 1, 1989, after determining that rod K-14 misalignment was due to binding, most likely caused by a small transient foreign particle and exercising rod K-14 successfully, the reactor was restarted. From August 1 through August 5, 1989, the reactor was shifted between Mode 1 and 2 to evaluate main turbine problems. On August 5, 1989, ascent to full power began. On August 9, 1989, while at 50% reactor power, a trip on overtemperature delta temperature (OT delta T) automatically shutdown the reactor. At 5:23 pm, August 14, 1989, after concluding the automatic reactor shutdown resulted from an intermittent OT delta T signal, whose exact cause could not be determined, and the simultaneous performance of a surveillance on another channel of OT delta T, the reactor was restarted. On September 2, 1989, 100% power was momentarily achieved then power was reduced to 99% when an overpower delta temperature (OP delta T) rod block occurred. The inspection period concluded with the reactor at 99% power with an evaluation in progress as to the cause of both OP and OT delta temperature rod blocks.

3. <u>Safety Verification (71707)</u>

<u>Operational Safety Verification</u>

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.

Daily the inspectors observed control room activities to verify the licensee's adherence to limiting conditions for operation 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 pertinent information was relayed to the oncoming shift personnel.

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.
(k) Proper storage of compressed gas bottles.

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

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 related to in-progress work activities.

The inspectors examined the licensee's nonconformance reports (NCRs) to confirm that deficiencies were identified and tracked by the system. Identified nonconformances were being tracked and followed to the completion of corrective action.

Routine inspections of the licensee's physical security program were performed in the areas of access control, organization and staffing, and detection and assessment systems. The inspectors observed the access control measures used at the entrance to the protected area, verified the integrity of portions of the protected area barrier and vital area barriers, and observed in several instances the implementation of compensatory measures upon breach of vital area barriers. Portions of the isolation zone were verified to be free of obstructions. Functioning of central and secondary alarm stations (including the use of CCTV monitors) was observed. On a sampling basis, the inspectors verified that the required minimum number of armed guards and individuals authorized to direct security activities were on site.

The inspectors conducted routine inspections of selected activities of the licensee's radiological protection program. A sampling of radiation work permits (RWP) was reviewed for completeness and adequacy of information. During the course of inspection activities and periodic tours of plant areas, the inspectors verified proper use of personnel monitoring equipment, observed individuals leaving the radiation controlled area and signing out on appropriate RWP's and observed the posting of radiation areas and contaminated areas. Posted radiation levels at locations within the fuel and auxiliary buildings were verified using both NRC and licensee portable survey meters. The involvement of health physics supervisors and engineers and their awareness of significant plant activities was assessed through conversations and reviews of RWP sign-in records.

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.

<u>Verification of Operator Certification of Medical Examination</u>

The inspectors evaluated the licensee's administrative system for assuring that medical examination requirements for licensed operators are acceptably implemented. The inspection included comparing licensed operator medical records against the licensee's "Certification of Medical Examination by Facility Licensee"-NRC Form 396. The inspectors found the licensee's administrative controls were effective to ensure licensed operators receive a medical examination every two years. The licensee training organization maintains the dates when each licensed operator requires a medical examination and informs the licensed operator when the examination is required. The NRC Form 396s are maintained in the licensee document storage vault and eventually microfiched. The inspectors also reviewed twenty-eight of the forty-six licensed operator's NRC Form 396s to assess whether or not medical examination were current. No deficiencies were noted.

No violations or deviations were identified.

4. Maintenance (62703)

The inspector observed corrective maintenance on a rod control drive mechanism. The licensee was performing Periodic Operating Test (POT) 15-1, "Control Rod Drive System Full-Length Rod Movement Verification," on August 31, 1989 when it was noted that the Shutdown Banks C/D would not insert. This test is performed monthly to verify the proper operation of the full-length rod clusters, drive mechanisms, and the associated control and indication circuits. The rods and associated step counters would give only outward motion whether selected to drive in or out. The Control Operator informed the Shift Supervisor and Instrumentation and Control, and entered into the 72 hour action statement of Technical Specification 3.1.3.1. Internal Event Report (ER) 89-147 was issued on this event.

The licensee discussed this problem with the Nuclear Steam System Supplier, Westinghouse. Three likely causes for the failure of the rods not to step in were identified: Card A-701 (Pulse Shaper) failure, Card A-307 (Logic) failure, or the input/output relay (K-17/K-18) failure.

The licensee initiated Maintenance Request (MR) 89-8373 to troubleshoot the problem. Work instructions were included with the MR; the MR was reviewed by Quality Control; and Quality Control hold points were established. During the conduct of the maintenance, the MR was refined several times to further categorize and isolate the failure. Quality Control involvement was evident each time. The licensee determined that the logic card failed and replaced the card.

The inspector verified the meters used in the conduct of maintenance were calibrated. He noted that the logic card came in a bag which said Non-Quality Related. Independently, the licensee's Quality Control Inspector came to the same conclusion, wrote a Non Conformance Report (NCR) 89-415 to document the Non Quality Related indication and wrote a Non Conforming Activity Report (NCAR) P89-397 as to how this part should have been restored. The inspectors will follow up on this as a course of routine inspection since a similar event happened previously as noted in Inspection Report 50-344/89-17.

With the facility in Mode 1, the inspector observed the return to service and operation of the Rod Control System. Plant licensed operators noted the step counter position, digital rod position indication (DRPI), and then exercised control rods. The inspector asked the control operator if he was sure that the Shutdown Bank Rods were at 226 steps since technical specification 3.1.5.4 requires that Shutdown Banks be greater than 225 steps in Modes 1 or 2. The operator appeared not to be familiar with that technical specification requirement. By actual DRPI indications (228 steps), the rods were greater than 225 steps, therefore, the requirements of the technical specification were met. Through routine followup, the inspectors will continue to evaluate operator knowledge of Technical Specifications.

No violations or deviations were identified.

5. Surveillance (61726)

Reactor Trip (RTB) Breaker Position Verification

On July 26, 1989, the licensee conducted an inspection of the reactor trip breakers and found the right hand side (RHS) latch was not fully engaged. An internal licensee event report (ER89-113) was written. As part of this event report, the licensee Quality Assurance organization recommended the corrective actions of training and posting operating instructions on the inside panel of the breaker cubicle door. These corrective actions were not implemented. This insensitivity by plant management to this important issue may have contributed to event recurrence. On August 1, 1989, a maintenance craftsman, while training another craftsman on breaker operation, noted the RHS latch was not fully latched. The previous event report was revised to incorporate this second event. As a result of the second incident of the Reactor Trip Breakers (RTB) not being fully latched, the licensee implemented a program to inspect the RTB's every week to ensure proper latch engagement and that RTB operation would only be performed by a trained electrician. Paragraph 8 further discusses the latch design function of the RTB's. Subsequent to each event, the breaker RHS latch was correctly latched to assure RTB design function.

The inspector observed the licensee perform one of the weekly inspections of the RTBs. The technician told the shift supervisor that he would be opening the RTB cabinets for inspection. The technician followed the instructions on MR 89-7631. The inspector reviewed the previous data sheets, and noted that the RHS latch of RTB A was bent. This was not considered by the licensee to be an operability issue.

Core Thermal Power Evaluation

The inspector reviewed Plant Operating Test (POT) 22-1, "Heat Balance Calibration," for technical adequacy and examined calculations performed by this procedure. The licensee performs a core thermal power calculation (calorimetric) daily when they are above 15% power by POT 22-1. This procedure is used daily to adjust or verify the accuracy of the Power Range Nuclear Instrumentation setpoints (Technical Specification Surveillance 4.3.1.1) which inputs into the Reactor Protection System.

The inspector reviewed the POT 22-1 data sheets, and determined that the data and results appeared reasonable by performing a rough calculation that confirmed the actual value obtained by the licensee for the calculation of total core power. The inspector also observed a calorimetric in progress. The procedure requires the plant to be at steady-state operation prior to obtaining calorimetric data. The parameters of feed water flow, water levels, steam generator blowdown flow, and primary pressure were not changed appreciably during the calorimetric.

On August 14, 1989, the inspector reviewed the last 30 calorimetric data sheets. During the review, the inspector determined that some of the data sheets were not in the vault. The data sheets from March 29, 1989 through April 5, 1989 were determined to be with the system engineer who reviews the data sheets for system performance. The inspector questioned the appropriateness of having QA records for that length of time. The inspector subsequently determined that the licensee's Administrative Order (AO) 7-1, "Plant Records" required QA records be kept for only 120 days without being installed in an approved facility or cabinet. The system engineer generated Non-Conforming Activity Report (NCAR) P89-368M. Because this licensee corrective action was prompt and appropriate, this violation was identified to the licensee as an non-cited Severity Level V violation.

The inspector verified that Steam Generator Pressure, Delta Temperature indications, and Nuclear Instruments all were in calibration. The inspector identified that the Feedwater Flow indicators used in the calorimetric were not always meeting their calibration frequency. The inspector determined that the plant had started up and was above 15% power with two feedwater flow instruments that did not meet their calibration frequency. Further investigation revealed that these feedwater flow indicators were not required by the Technical Specifications on the Trojan Surveillance Schedule (TSS). The inspectors questioned the appropriateness of this designation, since the calibration of this instrument is used to determine secondary heat balance. The licensee agreed with the inspectors, changed the designation, and committed to review their instrumentation list to verify that all the instruments used were appropriately designated.

The technical specification designations (on the TSS) used by the licensee are:

Priority	Definition
1	Required directly by the tech specs
2	Indirectly required by the tech specs, implied by the tech specs, or instrument used to verify tech spec operability.
3	Required by some commitment that PGE has made in writing.
4	Not required by tech specs, but controlled as if it were.
blank	Not required.

The inspector determined that the priority codes were either initially assigned when the TSS was placed in service, or were input into the TSS by the I&C Supervisor(s) if discrepancies were identified. The licensee should evaluate the appropriateness of this review technique.

The inspector had concerns about the licensee's computer program calculations. These concerns can be listed as follows:

(1) The licensee does not check the secondary heat balance with a primary heat balance, to see if the loops indicate about the same power. The inspector's calculations indicate that the maximum difference between the loops is almost 1% of total power.

(2) The licensee does not explicitly use the venturi equation for feedwater flow. The feedwater flow equation is basically constants times the square root of the differential pressure across the flow element. These constants are slightly different for each loop. The licensee uses an average of the four loop differential pressures to enter into their equation. The secondary system flowrate determined by the licensee is not mathematically the same as doing the caulculation on a per loop basis, although the results are close.

(3) The licensee also uses a value for the clean case of a venturi. Also, the flow to each loop can change from cycle to cycle, because of condenser tube fouling and steam generator tube plugging. This would not be reflected in the licensee's calculation.

(4) The licensee calorimetric does not individually account for CVCS makeup and letdown effects, Reactor Coolant Pump Heat, or insulation losses. These are basically assumed as constants and lumped together, and can be deduced from values in the data sheets. Since the CVCS conditions may vary, small errors can be introduced. The licensee's technique has no adverse impact on safety.

The NRC has developed their own computer program which can generate a heat balance (Refer to NUREG-1167); and does account for most of these phenomena. The inspector concluded overall that the licensee's calculations were acceptable, however improvements could be made by the licensee to more accurately perform the heat balance calculation.

The licensee's Quality Operations (QO) department was also evaluating the calorimetric concurrently with the NRC inspector. The QO inspector had a question about the validation and verification of the licensee's computer programs. The licensee uses two procedures to verify a computer program, Nuclear Division Procedure (NDP) 200-4, "Quality-Related Calculations" and NDP 200-5, "Quality-Related Computer Programs". The QO inspector initiated NCARs on how computer programs are validated.

The inspector also had concerns about how the program was validated. The licensee calorimetric program is a LOTUS 123 program. It is difficult to verify a LOTUS 123 program looking at the program listing, but the inspector did verify parts of the program with the licensee's help. The inspector will follow up on the licensee's computer program validation and verification.

One violation was identified.

6. Plant Startup from Refueling and Event Follow-up (71707, 92700, 93702)

From July 26, 1989, at 10:18 am, until September 2, 1989, at 3:35 am, low power physics and ascent to 100% reactor power were conducted. The following subsections document inspection activities and major events that occurred during the startup from the 1989 Refueling Outage.

Dropped Control Rod D-4

At 8:40 pm on July 27, 1989, with the reactor critical, and low power physics testing in progress, control rod D-4 dropped to the bottom of the core from 105 steps withdrawn. No anomalous or unusual indications were noted during or after the rod dropped. The reactor was immediately shutdown, shifted to Mode 3 and internal event report 89-112 initiated.

At 9:33 pm, the licensee identified that the lift coil power fuse had blown. At 9:35 pm, the fuse was replaced and control rod D-4 withdrawn and inserted (exercised) several times to verify operability. At 10:06 am, the licensee notified NRC of the event via the emergency notification system. At 4:05 am on July 28, 1989, subsequent to rod exercising and prior to restarting the reactor, control rod D-4 lift coil fuse was found blown for a second time. The licensee developed a troubleshooting strategy to identify the cause of the failure of the lift coil fuses.

Grounds were identified on the power supply cabling. The grounds were isolated to a module within containment electrical penetration NZ13, the electrical penetration for the lift coil power leads. Additional investigation identified that most of the wires within that module of containment electrical penetration NZ13 had ground indications. Further investigation disclosed that during the 1989 Refueling Outage, when the licensee was evaluating the cause of 14 and 16 gauge wires being easily pulled from containment electrical penetration modules (reported in NRC Inspection Reports 50-344/89-10 and 89-16 and Licensee Event Report 89-10), module X of NZ13 remained out of the containment electrical penetration exposed to air, for approximately six weeks. Because the penetration module was exposed to air, the licensee concluded the grounds resulted from moisture intrusion into the module. The licensee had previously experienced grounding problems when containment penetration modules were left exposed to open air during initial construction.

As corrective action, the licensee disconnected the grounded wires from module A of NZ13 and reconnected the wires to spare connections in other modules. The licensee also plans to consider maintenance procedure changes to assure that similar modules do not experience similar problems. The licensee continues to evaluate the integrity of containment electrical penetrations and has a long term action to replace the Bunker-Ramo electrical penetration during the 1990 Refueling Outage.

Misaligned Control Rod K-14

On July 31, 1989, at 5:22 pm, after resolution of the blown fuses associated with rod D-4, the reactor was restarted. At 6:14 pm, while continuously withdrawing control bank B rods, rod K-14 stopped moving out at 180 steps while the remainder of the control bank rods stepped out to

204 steps. The control operators did not identify any abnormal conditions other than the rod misalignment. Rod withdrawal was immediately stopped when the control operator recognized the rod, K-14, was misaligned. Subsequently, the operators determined the rod could not be withdrawn but could be inserted. The reactor was shutdown and an internal event report written.

Trojan Technical Specification (T.T.S.) 3.1.3.1. (applicability Modes 1 and 2) states "all rods shall be OPERABLE and positioned within + or - 12 steps (indicated position) of the group step counter demand position." When outside this condition, as was the case for this event, the technical specification action requires "SHUTDOWN MARGIN be determined to be within the requirements of T.T.S. 3.1.1.1 within one hour of discovery and be in HOT STANDBY within six hours." Shutdown Margin was verified and HOT STANDBY attained within 14 minutes of the rod being recognized as stuck. The licensee informed NRC of the event via the ENS at 8:12 pm and informed the NRC resident that evening. During the discussion between the Resident and Duty Plant General Manager (DPGM), the Resident asked the DPGM if a rod deviation alarm annunciated. The Resident Inspector was concerned that the rods were out of position by twice that allowed by T.T.S. 3.1.1.1 and a deviation alarm should have alerted the control operator to stop continuous rod withdrawal at a rod deviation of 12 steps. The DPGM told the Resident he would find out if the alarm was annunciated.

The licensee, in conjunction with the reactor vendor (Westinghouse), concluded that the most likely cause of rod K-14 being out of alignment and unable to be withdrawn was a foreign particle in the control rod mechanism. Subsequently, control rod K-14 was fully withdrawn and inserted exhibiting no signs of mechanical binding. At 5:22 am, August 1, 1989, the licensee conducted a reactor startup.

At 6:30 am, August 1, 1989, the resident inspectors, as follow-up inspection, discussed rod K-14 misalignment with the Shift Supervisor, Instrument and Control (I&C) Supervisor, and the Duty Plant General Manager. Again the inspectors questioned whether or not the rod deviation alarm annunciated. To their knowledge the alarm had not annunciated; however, the DPGM stated that had not been verified. The FSAR and station training manuals indicate the rod deviation alarm should have annunciated when K-14 was misaligned.

The inspectors, at 9:20 am, August 1, 1989, discussed the operation of the rod deviation monitor with the reactor engineer. He explained that the plant computer (P-250) generates the alarm signal that is transmitted to the control board annunciator. The reactor engineer also noted that each time the computer is restarted (rebooted) certain data, such as rod position, has to be re-entered. He noted that he had just rebooted the computer that morning and the deviation monitor appeared to be operating. Subsequently, the reactor engineer recognized the computer was not accepting rod position update data and at 12:00 pm on August 1, 1989, the rod deviation program was declared inoperable. Later, the licensee determined the rod deviation monitor program was not accepting the input rod data due to a change from partial length to full length control rods, corrected the program and declared the Rod Deviation Monitor Program operable.

The inspectors again reviewed the D-4 rod drop event of July 17, 1989, and noted that the rod deviation alarm was not received when D-4 dropped. During this event, the licensee operators had failed to recognize the rod deviation alarm should have annunciated. The inspectors reviewed records and concluded that the rod deviation monitor was inoperable from at least July 16, 1989, through August 1, 1989. With the Rod Deviation Monitor inoperable T.S.S. 4.1.3.1 requires rod position be verified once every four hours, however, rod position was being verified once every 12 hours. This is an apparent violation (50-344/89-20-01).

The inspectors next attempted to identify licensee requirements to verify operability of the rod deviation monitor. None could be identified. The inspectors concluded the root cause of the apparent violation was that no administrative requirement existed to verify the rod deviation monitor operable. Additionally, the inspectors, through discussions with licensed operators, identified a weakness in operator knowledge on the purpose and operation of the rod deviation monitor. The licensee training manual provides a description of the Monitor. At the exit the licensee committed to evaluate the operator training program for adequacy concerning the Rod Deviation Monitor and establish an administrative control to verify Rod Deviation Monitor operability.

Reactor Startup Observations of August 14, 1989

During the reactor restart begun at 5:53 pm, on August 14, 1989, while control rod Shutdown Bank C was being withdrawn, a computer alarm on control rod deviation was received. Operators responded rapidly by stopping control rod withdrawal and taking the actions specified in the associated annunciator response guide. The operators noted that the annunciator response guide was not up-to-date, in that it called for use of a deleted procedure, Off Normal Instruction (ONI) 2-7, "Reactor Control or Rod Position Indication Malfunction." Operators were familiar with the current procedure, Operating Instruction (OI) 2-4, "Control Rod Drive and Position Indication," and used that procedure. The Shift Supervisor (SS) initiated a change to the annunciator response guide to correct this deficiency. This problem was also the subject of a previous licensee critique. Licensee followup determined that the findings from the previous critique had not been corrected.

The operators determined that the problem was related to the plant computer and that the rod deviation alarm was inoperable. The SS requested clarification of the Technical Specification requirement for inoperable control rod deviation alarms from the Duty Plant General Manager. The guidance indicated that an increased surveillance frequency of rod position indication would compensate for a nonfunctioning alarm. Rod position verification was increased from 12 to 4 hours and repairs of the computer were delayed until completion of this Shutdown Bank C rod movement in order to avoid potential transients during maintenance.

Source Range Channel N32 Failures

Two channels of Source Range nuclear instruments monitor reactor power. These instruments normally provide reactor protection features during shutdown and startup conditions. Previous to the 1989 Refueling Outage, the Source Range nuclear instruments had exhibited erratic reliability, and during previous refueling outages cabling had been completely replaced. During the 1989 Refueling Outage, source range channel N32 failed in excess of ten times. The failures were generally intermittent random failures that would recur approximately every five minutes with the indicated count rate going to zero. On each occasion a maintenance request was written and the failure evaluated by the Instrument and Control (I&C) group. On each occasion after troubleshooting, that generally consisted of some of the connectors being verified tight and/or clean, some current/voltage verification and integrated circuit board replacement, the instrument was returned to service, a surveillance successfully performed and the instrument declared operable. Thereafter, the instrument operated for several days to several weeks and failed again . On July 29, 1989, at 9:30 am, channel N32 failed again. The licensee determined that the cause of that failure was a pre-amp connector not being fully engaged. For the remainder of this inspection period N-32 operated without failure.

The inspectors observed work and troubleshooting on the Source Range instrument several times during this inspection period. Generally, the troubleshooting plans were not comprehensive plans that verified ALL connectors were properly made and that incorporate long term signal monitoring. Licensee supervisor and management attention to the failure of N32 should be increased to assure a comprehensive plan to examine and monitor source range channel N32.

Reactor Trip on Over Temperature Delta Temperature (OT delta T)

On August 9, 1989, with the plant operating at approximately 50% power, a reactor trip occurred from the Over Temperature delta Temperature (OT delta T) protection circuitry. The OT delta T reactor trip is to provide core protection from a Departure from Nucleate Boiling (DNB). To provide this protection, a trip setpoint is continuously calculated by a function generator with inputs from the RCS average temperature (Tave), the RCS hot leg and cold leg temperature difference (delta T), another function generated with neutron flux as an input, and pressurizer pressure. The OT delta T calculated setpoint is compared to the actual delta temperature, and if the setpoint is less than actual delta T, a trip signal is generated. The OT delta T trip signal is a 2 out of 4 logic, with four channels each calculating a margin to trip. Prior to and at the time of the trip, the nuclear instruments to channel 3 were being reset, based on data provided by the reactor engineer. To enter this data, the licensee was performing Periodic Instrumentation and Control Test (PICT) 6-3, and PICT 11-1 for loop 3. Due to the work performed, the bistables to this channel were placed in the tripped state. This reduced the logic to trip from 2 out of 4 to 1 out of 3. At 12:20 pm, on August 9, 1989, the licensee received a signal to trip from another channel, which caused a reactor trip. Subsequent investigation indicated that the other trip signal came from channel 4, based on the sequence of events recorder which shows that channel 4 of OT delta T came in first, and that the OT delta T recorder happened to be set to record channel 4 and the recorder paper shows a spike at the time of the reactor trip. The trip signal on the sequence of events recorder was shown in for 25 cycles (approximately 1/2 second). The inspector arrived in the control room 3 minutes after the reactor trip and observed the reactor recovery.

The licensee, as a result of the reactor trip, initiated an internal event report and generated a plan of action to determine the cause of the trip. One of the corrective actions replaced three modules in the OT delta T circuit: the summator, Tave lead/lag module, and the trip bistable comparator. These OT delta T modules in the protection system at the time of the trip were bench tested and thermally cycled after being removed to determine if they would fail. No failures were found. The licensee also installed recorders on all 4 loops of the OT delta T circuit to monitor and record the input into OT delta T. Subsequent investigation of events preceding the trip revealed that the P-250 computer received alarms for channel 4 OT delta T going high and low approximately nine hours before the reactor trip. The OT delta T alarms on the computer were discussed by the shift supervisors at control room turnover but no actions had been taken by the time of the trip. The licensee replaced the modules, and began a power ascension. After ascending in power, the plant again received computer alarms. The plant also began to have the rod stop bistable annunciate intermittently for a duration of 1/2 second from the OT delta T channel 4 protecting circuit, which had not been previously seen. After receiving some bistable light flashes, the licensee also monitored the OT delta T indicators continually with a video camera, and recorded the intermittent OT delta T setpoint anomalies on loop 4. The licensee continued to receive rod block bistable flashes until August 28, 1989, when a measuring tape dropped by a civil engineer on top of the reactor protection cabinet containing OT delta T circuitry caused a series of OT delta T rod block bistables to flash. Observing the engineer on top of the cabinet, it became evident the rod block bistable trips were generated by a loose connection. The licensee investigated and found a loose connection on the recently replaced OT delta T lead/lag module. After replacing that module, channel 4 OT delta T has not generated any rod blocks. This bad connection probably did not explain the reactor trip since it was generated by a lead lag module that was not in the circuit at the time of the trip. Also computer alarms on OT delta T and OT delta T setpoint generator have been generated since the replacement of the module.

The inspectors noted that the OT delta T indicated setpoint is about 113% for loop 4, with the other loops indicated setpoint at 120-122%. The setpoint also appears to have significant variation. The licensee determined that the setpoint being generated in loop 4 was accurate since loop 4 T-hot is reading about 4.5 degrees F. higher than the other loops. The thermocouple detectors for the RCS temperature were verified to be in calibration by the licensee. The increased temperature does not appear to account for the difference in setpoint seen. The inspectors through manual calculation, attempted to verify the lower (actual seen) setpoint; however, the temperature difference appeared not to explain the total setpoint difference. The licensee committed to provide the inspectors additional information prior to considering this issue resolved.

The licensee did not determine the cause of the intermittent OT delta T trip signal; however, prior to restart an attempt was made to duplicate the signal. Of the possible causes listed by the licensee for the reactor trip, the only cause not dismissed by the licensee was the lowering of an OT delta T constant to meet a new Technical Specification amendment setpoint requirement. This could result in the peaks of channel noise being closer to the trip setpoint. However, at 50% power where the reactor trip occurred, the OT delta T setpoint was over 100% more than actual delta T. This lowering of the setpoint does not appear to the inspectors to have had any affect on why the reactor tripped. The licensee investigation was still continuing at the end of the inspection. The performance of the OT delta T reactor protection circuitry provides additional evidence that work practices in the I&C area should be closely evaluated.

One violation was identified.

7. Follow-up of Licensee Event Reports [LERs] (92700, 90712)

LER 89-06, Revision 1. (Closed), "Steam Dump Valve Failure Caused Engineered Safety Feature Actuation." This revised LER provided additional information (causes, corrective actions and commitments) on the April 6, 1989, events of erratic steam dump valve 507A operation, the failure of an instrument air line and the inability to manually drive bank A shutdown control rods.

The licensee concluded that the erratic operation of the steam dump valve PCV 507A was due to a shorted solenoid caused by a broken wire followed by a pneumatic valve operator air line for PCV 507A. The air line failed due to low cycle fatigue. The failure of A shutdown control rod bank to manually drive was determined to be due to a blown fuse on the power supply A phase for the Control Rod Drive Mechanism (CRDM) stationary gripper. Licensee corrective actions for each of these items were acceptable.

The inspectors observed the retesting and operation of the steam dumps subsequent to the extensive maintenance performed on the steam dumps during the outage. The steam dumps operated per design. The inspectors observed proper operation of the rod control system immediately subsequent to the replacement of the blown fuse. Since re-energization of the rod control system in preparation for recovery from the 1989 Refueling Outage, numerous deficiencies, such as additional fuses blowing, a dropped rod, and a misaligned rod, have occurred. Even though replacing the immediate deficiency of the blown fuse solved the inability of the A shutdown bank to drive on April 6, 1989, the reliability of the rod control system had been poor.

LER 89-08, Revision 1, (Closed), "Spent Fuel Pool Exhaust System Inoperable While Moving Fuel." This LER revised the previously reported failure to maintain the technical specification required negative pressure in the Spent Fuel Pool Exhaust System during refueling operation. The revision supplements the previous report by deferring from August 1 to November 30, 1989, the corrective action to identify through testing ventilation system lineups required to ensure AB-4 (Spent

Fuel Pool) ventilation system operability. This change is acceptable because refueling activities are not scheduled until April 1990.

LER 89-13, Revision 0, (Closed), "Cognitive Personnel Errors in Directing Work Resulted in an Inadvertent Reactor Trip Signal While Shutdown." This LER reported a reactor trip signal on Lo-Lo steam generator water level (SGWL) as a result of a Department Manager, without conferring with shift management, directing an instrument technician to remove temporarily installed jumpers that inserted a false (dummy) SGWL signal into the protection system. When the jumpers were removed, the actual low level in steam generators monitored by the reactor protection system and resulted in an engineer safety features (reactor trip breaker) actuation.

The licensee attributed the causes of the event to personnel bypassing normal work control system practices and inadequate access controls to the protection racks. Licensee corrective actions included disciplinary action, training, issuance of a plant wide memorandum that emphasized procedure compliance and a commitment to evaluate positive control over the reactor protection system racks.

The inspectors attended the licensee critique that discussed the event, and discussed the event with personnel involved and with Plant Managers. The inspectors noted that uncontrolled access to the reactor protection racks had been a previous concern and resulted in previous events. Additionally, since this event, an engineer was found to be walking on the top of the protection racks without being authorized. As corrective action, the licensee plans to implement positive controls over access to the reactor protection racks by December 29, 1989. The inspectors will continue to evaluate access to reactor protection system equipment during routine inspections.

LER 89-16, Revision 0, (Closed), "Inadequate Procedure and Personnel Errors Result in Power Operation with the Containment Recirculation Sump Protective Screen Not Installed." This LER reported containment recirculation sump deficiencies (missing top screen, screen gaps around penetrating piping) and inadequacies in containment recirculation sump inspections and inspection procedures. The details of these deficiencies are described in NRC Inspection Report 50-344/89-19. Additionally, licensee commitments and corrective actions are discussed in this Inspection Report and Inspection Report 50-344/89-22. At the Enforcement Conference conducted on August 24, 1989, the licensee committed to revise this LER when the results of their evaluation of the effects the debris found in the sump was complete.

The licensee concluded the cause of the event was inadequate procedural compliance, inadequate management involvement in plant events, inadequate procedures, failure to complete all construction activities and failure to verify the implementation of system design features. Corrective actions included revision to plant procedures, improved pre-inspection briefings, improved training, re-performance of system walkdowns to verify design basis, disciplinary action for personnel who did not perform to expectations and recognition for those who performed in excess of expectations.

No violations or deviations were identified.

8. Seismic Issues

Reactor Trip Breaker Not Engaged

The licensee identified that both the Reactor Trip Breakers (RTBs) did not have full engagement of the RTB positioning latches. Particularly, the Right Hand Side (RHS) latch was found not to be fully engaged on both breakers.

At 2:55 p.m. on July 26, 1989, the plant was in mode 2 when a licensee electrician initially discovered that the A RTB was not fully engaged. The plant was in Mode 2. An urgent MR was written to fix the problem, and this RTB was fully latched by 4:19 p.m. The Quality Operations department made several recommendations, which included more training for the operators and the use of visual aids to indicate proper breaker installation. The licensee wrote Event Report (ER) 89-113 on July 27, 1989 for this event. At 12:15 am on August 1, 1989, the control room log notes that the B RTB was also found not fully latched. Earlier, maintenance had found that the B RTB Right Hand Side latch was not fully in. The RTB was put into the latched position. The operations manager did not write a new event report; he merely added the new breaker onto ER 89-113 evaluation. The new entry was logged in the control room log at QA insistence. The corrective actions included that electrical maintenance department would take over responsibility for racking in the breakers, and weekly visual surveillances on the breakers would be performed to verify proper RHS latch engagement.

The inspector's had a concern about the seismic adequacy of the breakers. The RTB's are identified as Seismic Class I in section 3.2.1 of the FSAR. The licensee took measurements on a spare, identical RTB in the warehouse, and attempted to analyze the significance of not having the RHS latch fully engaged. Their analysis had not been fully checked as of September 21, 1989, but the results of the analysis revealed that the RTB could move 1/4" on the rail. Since the RTBs were tested with both latches engaged, the amount of movement analyzed renders the effect on operability indeterminate. In discussions with the licensee, the licensee's civil engineers believe that the only way to determine if the RTB would open would be to test it in the configuration with the RHS latch not engaged.

The licensee also has a letter from Westinghouse (dated 9/11/89) in which Westinghouse states that the RTB would open during the design basis seismic event event if the latch was not fully engaged.

Seismic Design Requirements

During the NRC inspection to determine the purpose of the Right Hand Side (RHS) latch of the reactor trip breaker, seismic qualification of the breaker was discussed. Questions raised by the inspector on seismic analysis techniques promoted the licensee to research the facility Final Safety Analysis Report (FSAR) for the method of seismic qualification to which PGE committed. Seismic Category I equipment is listed in section

3.2.1 of the FSAR, and the method of qualifying equipment is noted in section 3.7 of the FSAR. The licensee determined they had committed to seismically qualify Category I equipment by the Absolute Sum Method (FSAR section 3.7). Further, the licensee recognized that they had not always been analyzing their seismic design in accordance with section 3.7 of the FSAR; they were in cases using other methods as identified in Regulatory Guide 1.92, "Combining Modal Responses and Spatial Components in Seismic Response Analysis." The licensee had not committed to this Regulatory Guide (RG). The licensee in-house position (IHP) 1.92-1-1 to RG 1.92 noted that this guide is not applicable to Trojan. As a result of these findings, the licensee generated Non-Conforming Activity Report (NCAR) P89-380M, documenting that IHP 1.92-1-1 states that they will use chapter 3.7 of the FSAR for seismic design. One of the recommended actions noted on NCAR P89-380M was to determine which method to use in performing seismic design analysis in the future (FSAR 3.7 or RG 1.92) followed by making necessary revisions to the FSAR.

The inspector pointed out to the licensee that Trojan Technical Specification 5.7.1 states that the seismic design shall be designed and maintained to the original provisions contained in section 3.7 of the FSAR. The licensee revised NCAR P89-380M to recognize this problem. Specific examples where seismic analysis was performed using techniques different than those required by the FSAR include the modifications to the control room emergency ventilation system and the analysis on the design for the new battery rack.

At the conclusion of the inspection, the licensee was reviewing their calculations to verify that the other methods used do not give less conservative answers than by the methods specified in the FSAR. This use of other design methods than specified in the FSAR will be followed as an Unresolved Item pending full understanding of the licensee's design analysis methods and the inpact on system design (50-344/89-20-02).

Control Room Wall Seismic Analysis

On September 7, 1989, the licensee identified that part of the control room boundary seismic analysis that was to have been performed by Bechtel in 1987 had not been performed. The analysis that had not been performed concerned the wall above the entrance to the control room which is part of the control room boundary envelope. The control room envelope is required by Technical Specification to maintain the dose limits to the operators following an accident to low levels. The licensee initiated Non-Conformance Report (NCR) 89-399, to document this lack of seismic analysis.

The inspector became aware of this concern on September 12, 1989 as part of routine inspection activities. Per NDP 600-3, a licensee event report was submitted within five working days. The licensee noted that in their judgement and Bechtel's initial judgement, it was likely that the wall would be adequate. The civil supervisor showed the inspector a memo to that effect. Because the inspector thought that the JCO should be processed since the analysis had not yet been performed, he reviewed the licensee JCO file and noted a JCO had not been implemented. The licensee's procedure, NDP 100-15, "Preparatory Review and Approval of

Justifications for Continued Operation," establishes the requirements for preparation, review, and approval of JCO's. This procedure defines a JCO as "A written evaluation used to support the conclusion that the operation of the Trojan Nuclear Plant may continue during the time needed to correct a nonconforming or degraded condition or to resolve a regulatory issue." The inspector discussed this with the Manager of Technical Services and the Manager of Nuclear Plant Engineering (NPE) and stated that per NDP 100-15 it appeared a JCO was warranted. The Manager of NPE stated that he was not fully aware of the requirements of when to issue a JCO. The Manager of Technical Services concurred that a JCO warranted, and stated that a JCO would be written. NDP 100-15 also notes that, "the need to prepare a JCO may be determined by the responsible supervisor assigned to the corrective action evaluation of an NCR, NCAR, or ER or the reviewing department manager during the evaluation of a regulatory issue." The Manager of NPE was responsible for this JCO. As of Monday, September 18, 1989, this JCO was in the approval process.

One violation was identified.

9. <u>Severity Level V Violations</u>

As stated in Section V. A of 10 CFR Part 2, Appendix C, "General Statement of Policy and Procedure for NRC Enforcement Actions," 53 Fed. Reg. 40019 (October 13, 1988), a Notice of Violation will not normally be issued for isolated Severity Level V violations provided that the licensee has initiated appropriate corrective actions before the inspection ends. One apparent Severity Level V violation for which a Notice of Violation was not issued is discussed in paragraph 5 of this report.

10. <u>Exit Interview (30703)</u>

The inspectors met with the licensee representatives denoted in paragraph 1 on September 18, 1989, and with licensee management throughout the inspection period. In these meetings the inspectors summarized the scope and findings of the inspection activities.