U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No. 50-344/90-32

Docket No. 50-344

License No. NPF-1

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

Facility Name: Trojan

Inspection at: Rainier, Oregon

Inspection conducted: October 7 - November 17, 1990

Inspectors: R. C. Barr
Senior Resident Inspector

J. F. Melfi
Resident Inspector

Approved By: P. J. Morrill 12/14/90
P. J. Morrill, Chief Date Signed
Reactor Projects Section 1

Summary:

Inspection on October 7 - November 17, 1990 (Report 50-344/90-32)

Areas Inspected: Routine inspection of operational safety verification, maintenance, surveillance, event follow-up, and licensee event report follow-up. Inspection procedures 30702, 30703, 61726, 62702, 62703, 62704, 71707, 71710, 90712, 92700, 92701, 92702, and 93702 were used as guidance during the conduct of the inspection.

Results

General Conclusions and Specific Findings

The licensee should continue to pursue improvements to the root cause program and engineering programs as evidenced by their slow initial pursuit of the reactor coolant system flow and control rod drive problems.

Significant Safety Matters

None

Summary of Violations and Deviations

None

Open Items Summary

Four LERs and their revisions were closed.

# DETAILS

1. Persons Contacted

   a. Portland General Electric

      *J. E. Cross, Vice President, Nuclear
      *W. R. Robinson, Plant General Manager
      *T. D. Walt, General Manager, Technical Functions
       G. D. Hicks, General Manager, Plant Support
      *C. K. Seaman, General Manager, Nuclear Quality Assurance
      *C. P. Yundt, General Manager, Trojan Excellence
       M. J. Singh, Manager, Plant Modifications
      *J. W. Lentsch, Manager, Personnel Protection
       A. R. Ankrum, Manager, Nuclear Security
      *W. O. Nicholson, Manager, Operations
      *M. W. Hoffman, Manager, Nuclear Safety and Regulation
      *W. F. Peabody, Manager, Nuclear Plant Engineering
       M. B. Lackey, Manager, Planning and Control
      *J. F. Whelan, Manager, Maintenance
      *S. A. Bauer, Branch Manager, Nuclear Regulation
       J. Mody, Branch Manager, Plant Systems Engineering
       D. L. Nordstrom, Branch Manager, Quality Operations
       J. D. Reid, Branch Manager, Quality Support Services
       J. J. Taylor, Branch Manager, PM/EA
       G. L. Rich, Branch Manager, Radiation Protection
       G. P. Enterline, Branch Manager, Operations
       R. L. Russell, Outage Manager
       J. A. Benjamin, Supervisor, Quality Audits
      *W. J. Williams, Compliance Engineer

   b. Oregon Department of Energy

      *A. Bless, Resident 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

   At the beginning of the inspection period the facility was in Mode 1 at 100% power. On October 18, 1990, the licensee reduced reactor power to 98% to evaluate an apparent reactor coolant system (RCS) differential temperature of greater than 100% (section 6). On October 22, 1990, the control rod control system malfunctioned by automatically stepping in at the maximum rate (paragraph 5). On November 14, 1990, the licensee returned the facility to 100% power after verifying that RCS flow was within technical specification allowed values. The reporting period concluded with the facility at 100% power.

3. Operational Safety Verification (71707)

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 Corrective Action Program (CAP) 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 review 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.

No violations or deviations were identified.

4. <u>Engineered Safety Features (ESF) System Walkdown (71710)</u>

The Boric Acid Transfer pumps (BATPs) and associated piping to the Reactor Coolant System (RCS) via the Centrifugal Charging Pumps (CCPs) comprises the emergency boration flow path. The inspector walked down the Boric Acid Transfer Pumps and various support systems around the Boric Acid Storage Tanks (BASTs), which is the beginning of the emergency boration flow path.

In verifying the flowpath with the Piping and Instrument Diagram (P&ID), the inspector noted that the piping went through walls making it difficult to pick up the continuation of the piping. The inspector then took the isometric drawings for the boration flow path and continued to trace out as much of the flow path as was readily accessible. In doing so, the inspector noted that the piping went through several locked rooms and pipe chases. Where the inspector was able to verify the flow path, the inspector noted that the piping was not heat traced from the boric acid transfer pump room to the Volume Control Tank (VCT) blender room as shown on the P&ID, drawing M-202, sheet 2. The line was also noted to be heat traced in the Final Safety Analysis Report (FSAR, section 9.3.4.2.2.4). Heat tracing is required to keep the concentrated boric acid (7000-7700 ppm) in solution. The flowpath does not recirculate the solution, and at these concentrations, the boric acid could crystallize at 65 degrees F., resulting in blockage of the flowpath. The emergency boration flow path is required by the plant technical specifications and General Design Criteria (GDC) 26 as a diverse means for emergency reactivity control (other than control rods).

The inspector discussed his observation with the licensee, and requested that the licensee verify that the line was heat traced per design requirements. The licensee produced drawings which showed that the line was heat traced except in the rooms toured by the inspector. The inspector verified that the heat tracing was functional. The boration flow path line was not heat traced in several rooms because it was the original design intent that the rooms not be heat traced as indicated on the associated isometric drawings, because these rooms are usually at temperatures above 65 degrees F. The licensee also stated that the plant had not had boron precipitate in these lines before. The licensee further stated that they were going to update the FSAR to be more accurate.

In the process of updating the FSAR, the licensee determined that the auxiliary/fuel building ventilation system design could allow the subject rooms to go to 50 degrees F., which is below the crystallization point of boric acid. The crystallization of boric acid could result in a blockage of the emergency boration flow path. The licensee initiated Corrective Action Request (CAR) C90-1070 to monitor these rooms daily when the outside air temperature drops to 65 degrees F. to assure that the rooms are above 65 degrees F. The NPE mechanical manager stated the rooms were being monitored to determine if the line gets below 75 degrees F. and after this monitoring, the licensee would determine if any design changes were needed.

Subsequent inspection by region based inspectors identified a further heat trace concern with the rest of the flowpath. While not shown on the P&IDs as heat traced, it could still be susceptible to boric acid crystallization. The flowpath entering the VCT blender room is a two inch line and exiting the blender room is a four inch line to the CCPs and into the RCS. The inspector noted that part of the flowpath was heat traced when the plant had an operable Boron Injection Tank (BIT), but the BIT function and heat tracing had been removed by RDC 83-051.

The boration flowpath is currently operational based on not having boric acid crystallization in the line before and the monitoring of the line temperature by the licensee. The licensee is investigating the concern about the design basis of the boration system, since the majority of the flowpath is not heat traced. The inspectors will continue to followup on this item during a future routine inspection.

No violations or deviations were identified.

5. Maintenance (62702, 62703, 62704)

Steam Generator Pressure Alarms

On November 4, 1990, the licensee wrote a priority 1 maintenance request (MR) to investigate several annunciator alarms that did not have a valid cause for the annunciation. These were alarmed on the annunciator

(RONAN) system, however the plant computer did not indicate abnormal conditions. The alarms, the Steam Generator (SG) 'A' high delta pressure, 'A' SG low pressure, and 'A' SG low pressure alert, occurred at approximately the same time. The operators examined the process drawings and determined that the alarms were off of Pressure Transmitter (PT) 516. The licensee initiated Corrective Action Request (CAR) C90-5381.

The RONAN annunciators' indication of tripped bistables were cleared within one millisecond of tripping. The plant computer was monitoring these bistables on a 32 second scan rate and did not pick them up. The licensee determined that there were three possible sources for the faulty annunciation: the RONAN system, process instrumentation, or the transmitter itself.

The inspector observed qualified licensee technicians troubleshoot. All instrument connections checked were tight. The licensee found no problems with the process instrumentation. The licensee also looked at the RONAN system and determined that the annunciation for these three annunciators were off three different power supplies. These three power supplies were independent of each other and not susceptible to a common mode failure.

The technicians examined the transmitter since this was a common point of contact for the three annunciators. The licensee tried, by tapping components, to get the fault to recur, but were unsuccessful.

The licensee closed out the MR without determining a cause to the annunciation. The inspector was informed by the licensee that they were attributing this event to an unknown cause when the MR was closed. The licensee's evaluation of CAR C90-5381 was still open at the end of the inspection.

No violations or deviations were identified.

6. Surveillance (61726, 93702)

On October 25 and November 2, 1990, the inspector observed the licensee conduct Periodic Engineering Test (PET) 7-4, "RCS Total Flow Rate Measurement." The test was performed by qualified personnel and the instruments used were within their calibration frequency.

The test was performed due to observations since startup from the last outage that flow indication had decreased by approximately 2% (7500 gpm), concurrent with a increase (2%) in temperature across the reactor core (delta T), and a decline in all Reactor Coolant Pump (RCP) amperages of 20-30 amps. All of these indications are consistent in that they imply a RCS flow decrease. Subsequent to the test, the licensee determined the actual flow decrease appeared to have been gradual, stopping in August, and stabilizing at a lower flow rate.

The test observed was required by Technical Specification 4.2.3.4 and 4.2.5 to be done at the beginning of every startup from a refueling outage and verified that the actual Reactor Coolant System (RCS) flow was greater than 354,000 gallons per minute (gpm). The minimum flow is required to address departure from nucleate boiling concerns. To verify that core flow is above an actual flow of 354,000 gpm and to account for possible instrument inaccuracies, a measured flow of 368,000 gpm is required.

The loop RCS flow was determined mathematically by calculating the heat removed by the loop minus the effective heat input by the Reactor Coolant Pump (RCP) divided by the enthalpy difference between the RCS hot leg and cold leg. Enthalpy was determined from steam tables based on the pressure and the temperature of the fluid. Temperature was determined by installed Resistance Temperature Detectors (RTDs) around which a small amount of the RCS flow is continuously passed. Pressure was determined from a pressure sensing instrument off the pressurizer. The total RCS flow was then calculated by adding the flow from all the loops.

The licensee's test allowed use of RTD data from the instrument racks (which use a signal processed from the RTDs) or by determining the temperature off the installed spare RTDs via calibration tables. The licensee performed the test using the instrumentation racks on July 16 and 17, 1990, and reported the flow to be 377,364 gpm at 87.1% power, and 375,367 gpm at 100% power. The licensee reperformed the test on October 25, 1990, and the licensee's calculation of the RCS flow rate was 367,662 gpm using the rack data, and 374,792 gpm using the installed spare RTDs. The inspector reviewed the completed data sheets and concluded that these numbers (October 25) were incorrect due to interpolation errors. Using the licensee's instrument values, the inspector determined that the correct numbers for flow were 367,535 gpm using the racks, or 372,643 gpm using the spare RTD's. Since the rack data was used for a determination of the RCS flow rate in July, a comparison of the flowrate in October indicates a flow decline of about 7800 gpm. This is also consistent with the observed flow decline on the instruments.

On July 16, 1990, the reactor engineer, because flow values were greater than expected, wrote several maintenance requests (MRs) to evaluate the RCS flow indication on several instruments. The MRs (90-7923 through 90-7928) were originally assigned a priority 2, but were subsequently assigned as routine. The flow indication was looked at on August 22, 1990, and all of the indicators were found to be within tolerance. No flow indications were greater than 0.21% from the indicated value, therefore no re-calibrations were performed.

As noted above, using the instrumentation racks as a reference, the RCS flow at 100% power indicated a decrease of about 7800 gpm which is close to the 2% flow decrease observed in the flow indications (7500 gpm). In conjunction with the delta T and RCP amperage information, this strongly implies that RCS flow decreased. The licensee concluded that the data used by the spare RTD's is more accurate since there is no intervening electronic modules that could introduce signal error. The spare RTD data indicated that the RCS flow was above the required 368,000 gpm. Since there was no data taken on the spare RTD values in July, it was not known if the spare RTDs would have shown the same decrease.

Calculated Flow Methodology

The inspector also reviewed the licensee's methodology for determining flow. The inspector was concerned whether the licensee's method for determining flow was appropriate. The inspector concluded the licensee's approach approximated actual RCS flow, but there were several inaccuracies in the licensee's approach. While the magnitude of the errors is small, they exist and can be nonconservative. These errors involve the calorimetric input into the RCS flow calculation, methodology errors in the calculation, and the values of assumed constants.

The licensee uses a calorimetric to determine the total heat removed by the steam generators. Since the licensee does not determine the heat removed on a loop basis, the averaging technique used by the licensee gives a higher secondary power than actual (by 0.02%). The licensee then takes the arithmetic average of the four loop temperatures to determine the enthalpy difference, subtracts an assumed amount for pump heat and piping losses, and determines the total RCS flow. Since the calorimetric overestimates the heat removed from the RCS and the net effect of pump heat is lower than actual, this overestimates RCS flow. The total effect of these overestimations is about 0.07% or about 250 gpm higher.

The licensee partitions the flow to each of the loops to determine each loop flow and to verify the setting of the RCS low flow trips. Due to cancelling methodology errors from where the heat removal was overestimated, the total error in loop flow is only off by approximately 100 gallons.

The licensee assumes several constants in the calculation of RCS flow. These assumed constants include 1) the net heat value for the RCP pump and piping losses, 2) the assumed value to bring RCS pressure to absolute pressure vice gauge pressure and 3) the implicit assumption that all RCS loops carry exactly 25% of the total flow.

The licensee uses an assumed value of 11.7 thermal MegaWatts (MWt) for the net effect of RCP heat and piping losses. The inspector noted that by actual calculation, the net effect of these losses is 13.2 MWt.

The licensee also assumes that the absolute pressure of the RCS is 14.7 psi plus the indicated value. The actual value of the absolute RCS pressure is the absolute pressure of the outside air, plus the relative pressure difference between the containment and the outside, plus the indicated value of the RCS pressure. The Technical Specifications allow the containment to vary by 2.7 (+1.6, -1.1) psi and this pressure difference could account for a calculated RCS flow difference of 45 gpm, or 0.01% of the total RCS flow.

The licensee makes an implicit assumption that each of the loops carry exactly 25% of the flow when they average the RCS flow temperatures. Actual loop flow is between 24.7% to 25.3% of the total flow. Since the licensee does not use a weighted average when determining temperature, this could translate into a temperature error for the hot leg or cold leg temperature. The enthalpy values are determined from the average temperatures. This may or may not introduce errors in the licensee's flow rate. For example, for the data taken on October 25, 1990, the o.. erence between adding all of the loop flows compared to the reported total flow rate was over 100 gpm (about 0.03%). The total errors found by the inspectors can add up to about 0.1%, which is not taken into account by the licensee.

RCS Flow Error Analysis

The inspectors raised questions about the accuracy of the licensee's measurement of RCS flow and what the actual errors could be. The amount of inaccuracy in the calculation has a direct effect on the required values to be verified. A higher inaccuracy would mean that the technical specification required value would have to be higher. The licensee performed an error analysis and determined that their instrument inaccuracies are 1.8% for the calorimetric, and 3.1% for the RCS flow determination. The assumed errors for the calorimetric and the RCS flow calculation assumed by the vendor are 2.0% and 3.5% respectively. The main contributors for the accuracy of the flowrate are the main feedwater flow indications (major effect on the calorimetric), and the hot leg and cold leg temperatures. The licensee is apparently within the required accuracy even accounting for the methodology errors.

The licensee's analysis was reviewed by the NRC staff and questions about the technical adequacy and assumptions used in the analysis were noted. The vendor's methodology to determine the total possible error was to take the Square Root of the Sum of the Squares (SRSS) of the errors. It was noted that the licensee used a square root twice methodology, which reduced the error. The licensee stated that their approach was valid and their error analysis was accurate. The adequacy of the licensee's accuracy calculation is still under NRC staff review and will continue to be followed up by the resident staff.

Possible Explanations

The licensee has several postulated explanations for the RCS flow decrease. These possible explanations include instrument drift, RCS flow stratification, RCP speed change, and a possible contamination buildup/removal on the pump impeller. These possible explanations are discussed below.

The likelihood of instrument drift affecting all the instruments (12 flow indicators, 4 delta T indicators) in the same direction appears very small. The licensee did look at the calibration of the temperature indicators and did find some drift in one hot leg temperature and one cold leg temperature element. The change added about 700 gallons to the indicated flow. The possibility of instrument drift can account for some of the indicated flow difference, but not all of the observed decrease.

It has also been noted by the licensee that the total inaccuracy of the flow measurement is 12,000 to 13,000 gpm, and the observed variation in the flow rate is within the accuracy of the measurement. This does not explain why all the instruments should show the same indication change. Further, the total inaccuracy of the measurement is composed of various components, most of which are set and do not change. While the total inaccuracy of the measurement is 12000 to 13000 gpm, if the same measurement method and instruments are used, it should not show this magnitude of variation.

The RCS flow stratification explanation assumes that the RCS flow is not perfectly mixed. Due to the low leakage core design at Trojan, the outer periphery of the core produces less power than the core originally did in 1975. The coolant from the periphery is of a lower temperature and the coolant from the center of the core is of a higher temperature than the original core. The flow in the hot legs is therefore not of a uniform temperature. The scoops that take the coolant out of the RCS hot legs to measure the temperature are therefore not receiving a representative sample of the average RCS hot leg temperature, but a slightly higher average temperature. The calculated core flow would therefore be less since the indication of temperature is different than actual.

This phenomenon has been postulated and seen before at other plants. However, the licensee has had low leakage cores for several cycles and this is the first time this has been seen at Trojan. This does not seem a likely explanation since the previous low leakage cores did not display this phenomenon.

The RCPs were noted to be operating at higher amperages at the beginning of the cycle. There is also some indication that the plant was operating at a higher grid voltage during the time that the original test was performed. This implies that the RCP motors were drawing more energy and pumping harder.

The RCP speed change theory assumes that the RCPs were spinning slightly faster at the beginning of the cycle. The RCP motor is a single speed, synchronous motor, operating nominally at 1200 revolutions per minute (rpm). The amount of rpm's that the RCP motor is from synchronous speed, divided by the synchronous speed, is referred to as the slip of the motor. The motor would nominally run at 1186 rpm. The maximum amount of slip the motor has is 1.17%. The licensee estimates that the RCP motor could have gone to approximately 1190 rpm. The amount of slip in this case is 0.83%. The amount of change that the RCPs could have had on the RCS flow was approximately 0.33%. Since the ratio of the speed is proportional to the pump flow, this could account for approximately 1200 gpm. However, even if the motor could be fully synchronous, it would only account for approximately 4300 gpm.

The possible change in speed of the RCP motor is theorized. To actually verify if it happened, the licensee is considering the performance of a temporary plant test to change the voltage on the bus to the RCPs and observe the effect on the flow. At the end of the inspection period, the licensee had not decided if they were going to perform the test.

The last explanation involves the possible contamination buildup/removal on the pump impeller. This explanation assumes that there was some film buildup on the impeller surface and as time progressed for this cycle, it wore off. This postulated removal of contamination could change the impeller characteristics and could therefore have caused a flow change.

This was apparently observed at a foreign plant after RCS pH had been changed.

The RCS pH at this plant did not significantly change over this cycle and has been approximately where it has been for several cycles. The licensee did not observe an increase in the amount of contamination leaving the RCS. The licensee stated that they did not rule out this option, but did not think it likely. The licensee was also not aware of any mechanism that would have caused a contamination to preferentially buildup on the impeller.

In summary, the inspectors made the following observations associated with the licensee's disposition of the RCS flow issue:

- o The licensee performed a calculation of RCS flow and did not interpolate values from the steam tables correctly.
- o The licensee has several small errors in the assumptions they make in their calculation. While the magnitude of these errors is not large, they can be eliminated for a more accurate calculation.
- o The actual flow in the RCS does appear to be greater than technical specification required flows; so the licensee is within their safety analysis.
- o None of the explanations postulated by the licensee appear likely to account for all of the observed change in RCS flow.
- o The flow accuracy calculation is being questioned by the staff for the appropriateness of some of the assumptions. This will be followed up by the resident staff.

The licensee plans to perform the RCS flow test monthly to assure the flowrate is not decreasing. The inspectors will continue to monitor the flowrate of the RCS.

No violations or deviations were identified.

7. Event Follow-up (93702, 62703, 92701)

Unexplained Rod Motion

On October 22, 1990, the control rod control system malfunctioned by automatically inserting the controld rods (rods) at greater than 60 steps/minute. After verifying that there was no transient to cause the rods to move in, the control room operators placed the rods in manual, stopping the rod motion after a several step insertion. The licensee wrote a priority 1 Maintenance Request (MR) to investigate and monitor the rod control system.

During initial questioning of the operators, the inspectors were informed that the rod control system stepped rods in three times on October 22, 1990, however the control room logs only indicated that the rods had stepped in twice. Additionally, licensee management was not informed of the correct number of insertions. The inspectors raised the concern about the control room log accuracy with the licensee who then changed the log. The licensee noted that the rods stepped in one more time with a late entry into the logs at 0902 on October 30, 1990. The inspectors also raised questions concerning adherence with Technical Specification 3.1.3.1, action c. The licensee concluded action c was not applicable because the control rods were movable and tripable. The inspector verified the licensee interpretation.

The rod control system is designed to compensate for a 10% full power step load decrease and maintain the Reactor Coolant System (RCS) within 1.5 degrees F. of the desired temperature. The rod control system receives inputs from the power range nuclear instruments, the RCS average temperatures, and reference signals generated by the first stage turbine impulse pressure. The rod control system is divided into two major circuits, the power mismatch circuit and the temperature mismatch circuit. The power mismatch circuit receives inputs from the highest indicating nuclear instrument and impulse pressure, and responds to a rapidly changing load. The temperature mismatch circuit receives inputs from the highest indication of RCS average temperature and a reference temperature (generated from first stage impulse pressure), and moves the rods to maintain the desired reference temperature setpoint.

The inspector observed the licensee connect the monitoring instrumentation and troubleshoot. The licensee performed the troubleshooting in accordance with the work instructions. No instrumentation anomalies were found. The inspector noted that the equipment used was within its calibration cycle and the connections were tight.

The control rods remained in the manual mode and the licensee connected a recorder to monitor the signals from the power mismatch circuit and the temperature mismatch circuit. An anomalous signal from the power mismatch side of the rod control system was detected that may have caused rods to move, but no motion occurred since the rods were in manual. Further, with the rods in manual, the rod control system would not perform its design function if there was a load rejection. The licensee then decided to return the rods to automatic. The licensee issued night orders to keep at least one operator at all times in the vicinity of the manual switch as a precautionary measure. When in automatic, the rod control system received no anomalous signals to drive the rods in, or any indication of anomalous signals on the strip charts. There was one external event in which the system engineer moved a recorder wire by hand when he replaced a pin in the recorder. When the system engineer moved the wire, the rods moved momentarily. The licensee wrote CAR C90-5379 to document this event. Subsequently, the licensee installed isolation devices between the recorder and the circuit so this would not occur again. On November 9, 1990, because no further anomalous signals had been received, the recorder was disconnected.

On November 12, 1990, the rod control system received an anomalous signal to insert. Since the MR was not closed, the licensee used the same MR and reinstalled a different recorder on the system and added six more monitoring points after this event. The licensee used the isolation device and reinitiated the precautionary measures for the operators. The licensee is presently monitoring ten points, primarily around lead/lag modules in the circuit. As of the end of the inspection period, the licensee was continuing to monitor the rod control system.

Because the plant operates with the control rods basically fully withdrawn, the potential reactivity effect of a spurious control rod withdrawl is very small. Additionally, the protective system provides for a rod block if power goes sufficiently above 100%. The operators have been alerted to the issue and can easily terminate rod motion if need be by switching the rod control system to manual. For these reasons, the inspectors concluded that the direct safety significance of the problem was such that the licensee's approach to troubleshooting the problem appeared adequate.

The inspectors are continuing to follow the licensee's actions on the rod control system.

No violations or deviations were identified.

8. Follow-up of Licensee Event Reports (LER) [90712, 92700]

LER 89-29, Revision 2 (Closed), "Fire Dampers, Penetrations and Sprinkler/Deluge Surveillances Not Performed Within Required Time Frames Due to Cognitive Personnel Errors." This revised LER provided additional information with respect to the description, causes and corrective actions associated with missing the technical specification surveillances. Previous inspection on this LER has been documented in NRC inspection reports 50-344/89-33, 50-344/90-02 and 50-344/90-06. The inspector concluded that licensee corrective actions that included surveillance tracking improvement should prevent future missed surveillances in this area. Additionally, in a Special Report dated November 15, 1990, (WRR-148-90SR#9-1), the licensee, as a result of a fire damper design review, committed to replace or modify Technical Specification fire dampers to enable fire damper testing under full flow. Based on licensee completed or proposed corrective actions, this LER is closed.

LER 90-12, Revision 0 and Revision 1, (Closed), "Engineered Safety Features (ESF) Electrical Switchgear Could Experience Common Mode Failure From Elevated Temperatures as a Result of ESF Room Cooler Fan Design Error." The initial and revised LERs described the licensee's discovery of a design error that resulted in the potential for the electrical switchgear rooms, which contain safety related electrical distribution equipment, to exceed design temperatures during a loss of off-site power and a safety injection. Previous inspection on this event was documented in NRC inspection report 50-344/90-24. In Revision 1 of this LER, the licensee concluded the significance of this event with respect to safety was minimal. The licensee reached the conclusion based on actions required to be taken by operators as a result of facility procedures. These required operator actions would have resulted in temperatures in ESF electrical switchgear rooms not exceeding 120 degrees F. In a separate engineering evaluation, Elevated Ambient Temperature Operability Report, the licensee concluded the safety equipment in these rooms would be operable for seven days at temperatures of at least 120 degrees F. and for a year or more at temperatures up to 104 degrees F.

The inspectors verified that licensee procedures did contain requirements that would have resulted in plant operators accessing, questioning and starting the room coolers in the affected ESF switchgear rooms. The inspectors also reviewed the licensee's Elevated Ambient Temperature Operability Report for adequacy. Based on licensee corrective actions and the limited safety significance of the event, this LER is closed.

LER 90-15, Revision 0 and Revision 1, (Closed), "Inadequate Original Design of Control Room Emergency Ventilation System Coolers Results in Plant Operation in an Unanalyzed Condition." The initial and revised LERs described the licensee's discovery of the potential to exceed the control room design temperature during a design basis accident when off-site power remained available. Previous inspection on this event was documented in NRC inspection report 50-344/90-24. In Revision 1 of this LER, the licensee concluded, based on refined calculations and the conservatism of the assumptions of the calculations, it was unlikely that the Control Room Emergency Ventilation System could not maintain temperatures within the 110 degrees F. limit under design basis accident conditions when off-site power remained available. However, calculations performed by the architect-engineer (A-E) indicate that after seven days the control room would have exceeded 110 degrees F.

The inspectors reviewed the refined control room temperature calculations, licensee procedures and the Final Safety Analysis Report (FSAR). The FSAR requires that the control room temperature remain less than 110 degrees F. for operator habitability concerns. Facility procedures permit various combinations of normal and emergency control room coolers to maintain control room temperature less than 110 degrees F. The inspectors' review and evaluation of the A-E calculation found that under the worst case assumptions and without operator intervention, the control room temperature would have exceeded 110 degrees F. prior to the 1988 CB-16 design addition.

Because of the extremely low likelihood of worst case design conditions lasting in excess of seven days, other conservatisms in the design assumptions and the likelihood of operator intervention, the inspectors concluded the safety significance of this event was limited. Based on the limited safety significance and licensee corrective actions, (addition of CB-16) this LER is closed.

LER 90-18, Revision 0 and Revision 1, (Closed), "Lack of Periodic Cooler Inspection and Cleaning Program Results in Excessive Cooler Blockage and Operation in an Unanalyzed Condition." This LER described the licensee's discovery that safety related room coolers were blocked beyond their design margin by silt and clam shells.

On May 25, 1990, while conducting inspection of engineered safety feature (ESF) room coolers for silting and blockage, the licensee discovered the A train electrical switchgear room coolers did not have sufficient capacity, as a result of silting and blockage, to meet design requirements. The licensee concluded the cause of the restricted flow and blockage was the lack of a periodic room cooler inspection and cleaning program. As immediate corrective action, the licensee inspected and cleaned all ESF service water supplied room coolers with the exception of the cable spreading room (3) and the Control Room Emergency Ventilation (2) room coolers, which were deferred due to large design margins and alternate available cooling, respectively. Long term licensee corrective actions include cleaning and inspecting the remaining ESF room coolers during the 1991 Refueling Outage, developing a preventative maintenance and inspection plan by September 15, 1990, and reviewing selected room heat loads and cooler capacities for potential design improvements. In revision 1 to this LER, the licensee concluded the safety significance of this event was minor. The licensee concluded the cooler blockage would result in the ESF switchgear room exceeding the design temperature by 4 degrees F. (108 degrees F. vice 104 degrees F.). Because the components of the room could withstand 120 degrees F. for seven days without damage, the licensee concluded the safety significance was minor.

The inspectors observed the cleaning and inspections of several of the room coolers as part of routine and followup inspection. The inspectors discussed with plant managers and plant systems engineers the results of previous inspections of room coolers. The inspectors noted that the documentation of previous heat exchanger cleanings and inspections was not sufficiently detailed to obtain a historical trend for fouling. The inspectors reviewed the licensee's response to NRC Generic Letter 89-13 "Service Water System Problems Affecting Safety-Related Equipment," and determined the licensee was complying with the actions listed in their response. The inspectors reviewed the licensee cooler inspection program for the 1991 Outage and long term inspection of service water coolers. Based on licensee completed and proposed corrective actions and the minor safety significance of this event, this LER is closed.

No violations or deviations were identified.

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

The inspectors met with the licensee representatives denoted in paragraph 1 on December 10, 1990, and with licensee management throughout the inspection period. In these meetings the inspectors summarized the scope and findings of the inspection activities.