U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.	94-07 94-07
Docket Nos.	50-334 50-412
License Nos.	DPR-66 NPF-73
Licensee:	Duquesne Light Company One Oxford Center 301 Grant Street Pittsburgh, PA 15279
Facility:	Beaver Valley Power Station, Units 1 and 2
Location:	Shippingport, Pennsylvania
Inspection Period:	March 15 - April 18, 1994
Inspectors:	Lawrence W. Rossbach, Senior Resident Inspector Peter P. Sena, Resident Inspector Scot A. Greenlee, Resident Inspector David C. Lew, Project Engineer

Approved by: W. J. Lazarus, Chief, Reactor Projects Section 3B — 5/4/94 Date

Inspection Summary

This inspection report documents the safety inspections conducted during day and backshift hours of station activities in the areas of: plant operations; maintenance and surveillance; engineering; plant support; and safety assessment/quality verification.

9405120008 940505
PDR ADOCK 05000334
Q PDR

EXECUTIVE SUMMARY

Beaver Valley Power Station
Report Nos. 50-334/94-07 & 50-412/94-07

Plant Operations

The inspectors found several deficiencies which should have been previously identified, evaluated and/or corrected by the licensee. These deficiencies included: boric acid deposits on Unit 1 low head safety injection system components; a safety injection flow orifice installed backwards; a broken locking device on a charging pump suction valve; and various control room deficiencies. The Unit 2 auxiliary feedwater system material condition was excellent. Corrective actions for a previous violation (50-412/93-30-01) involving inadvertent deactivation of a containment isolation signal were found to be appropriate.

Maintenance

Several maintenance activities indicated the need for more attention to detail and procedural adherence. The problems encountered during the period included: an inadvertent engineered safety features actuation when an operator operated test equipment on the wrong train; missing or skipping steps in procedures; and not filling out Jumper/Lifted Lead forms. One example of excellent procedure use and self-checking techniques was noted.

During calibration of a power range nuclear instrument, the inspectors found that the licensee was not taking actions to place the channel in a tripped condition. This issue was identified as an **unresolved item (50-412/94-07-01)**.

The licensee deleted the requirement to measure pump flow during some in-service tests. Once identified by the inspectors, the licensee corrected the deficiency.

Weaknesses in the control over switchyard work became apparent when a worker opened a breaker for relay room lighting. Additional controls were immediately placed on switchyard work while long-term controls are being finalized.

Engineering

The inspectors were not able to conclude that the licensee's heat exchanger monitoring program demonstrated that the heat exchangers would perform satisfactorily under design basis conditions. This conclusion was primarily based on lack of documentation that heat exchanger flow rates remain satisfactory throughout an operating cycle. This issue was identified as an **unresolved item (50-334/94-07-02 and 50-412/94-07-02)**.

(EXECUTIVE SUMMARY CONTINUED)

The inspectors determined that the licensee did not have air flow set in the Unit 2 cable vaults as required by their environmental qualification calculations. The licensee adjusted the air flows to correct the deficiency, but is still evaluating the safety significance. This issue was also identified as an **unresolved item (50-412/94-07-03)**.

A system engineer did an outstanding job in recognizing a significant deficiency in the Unit 1 steam generator feedwater system. This indicated a strength in the licensee's system engineer program.

Plant Support

A chemistry analyst reached across a high radiation area (HRA) boundary to obtain a sample without implementing HRA controls. The licensee is taking further action to ensure that station personnel understand that this practice is contrary to company policy.

At the request of the Chemistry Department, the Quality Services Unit conducted an assessment of boron analysis techniques and procedures, and then conducted training based on the results. The assessment and the training were of high quality, and were evidence of a good chemistry program.

The licensee completed an extensive search for incore detectors and concluded that four missing detectors had been disposed of as radioactive waste. Current controls provide adequate accountability for all remaining incore detectors.

TABLE OF CONTENTS

DETAILS

1.0 MAJOR FACILITY ACTIVITIES

Unit 1 reduced power to 32 percent on March 15 to repair a main feedwater flow control valve actuator. This is discussed in Section 4.4. Unit 1 operated at full power for the remainder of this inspection period except for minor power reductions for planned surveillance and when cooling tower efficiencies declined due to high ambient temperatures.

Unit 2 operated at full power throughout this inspection period without any significant operational events.

2.0 PLANT OPERATIONS (71707, 71710)

2.1 Operational Safety Verification

Using applicable drawings and check-off lists, the inspectors independently verified safety system operability by performing control panel and field walkdowns of the following systems: high head safety injection, low head safety injection, and river water. These systems were properly aligned. The inspectors observed plant operation and verified that the plant was operated safely and in accordance with licensee procedures and regulatory requirements. Regular tours were conducted of the following plant areas:

- Control Room
- Auxiliary Buildings
- Switchgear Areas
- Access Control Points
- Protected Areas
- Spent Fuel Buildings
- Diesel Generator Buildings
- Safeguards Areas
- Service Buildings
- Turbine Buildings
- Intake Structure
- Yard Areas
- Containment Penetration Areas

During the course of the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration, and plant conditions. The inspectors verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. The inspectors found that control room access was properly controlled and a professional atmosphere was maintained. Inspectors' comments or questions resulting from these reviews were resolved by licensee personnel.

Control room instruments and plant computer indications were observed for correlation between channels and for conformance with technical specification (TS) requirements. Operability of engineered safety features, other safety related systems, and onsite and offsite power sources were verified. The inspectors observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Compliance with TS and implementation of appropriate action statements for equipment out of service was inspected. Logs and records were reviewed to determine if entries were accurate and identified equipment status or deficiencies. These records included operating logs, turnover sheets, system safety tags, and the jumper and lifted lead book. The inspectors also examined the condition of various fire protection, meteorological, and seismic monitoring systems.

2.2 Safety System Walkdowns

The inspectors conducted detailed walkdowns of the accessible portions of the Unit 1 low head safety injection (LHSI) system and the Unit 2 auxiliary feedwater (AFW) system. The inspector used probabilistic risk guidance, including NUREG/CR-5835 PNL-7925, "Auxiliary Feedwater System Risk-Based Inspection Guide for Beaver Valley Units 1 and 2 Nuclear Power Plants," during conduct of the walkdowns. Generally, the walkdowns consisted of verifying that system components were properly aligned, confirming that instrumentation readings were consistent with normal expected values, and identifying equipment conditions and items which may degrade system performance. The inspector concluded that the systems were capable of performing their intended safety functions. Specific observations are discussed below.

<u>Unit 1 LHSI System</u>

Overall, the material condition and housekeeping in the vicinity of the LHSI system was good; however, the inspectors observed several components with boric acid deposits. These components included both pump discharge check valves, both pump suction valve bonnets, and both pump discharge flanges. These components are held together by carbon steel bolts, which are susceptible to accelerated corrosion if wetted with boric acid. The condition of many of these bolts could not be observed. The licensee is evaluating the affect that the boron deposits may have on the system.

The inspector identified that a flow orifice in the 'B' pump discharge line was installed backwards. The orifice was a square edge type, and its performance was not affected by orientation. However, in investigating this issue, the licensee discovered several other orifices, at both units, that were installed incorrectly. The licensee has resolved all of the immediate safety concerns associated with these orifices, and is continuing to evaluate the root causes and long term corrective actions for the deficiencies. Some of the deficiencies appear to be associated with original installation. The inspectors reviewed the licensee's actions following receipt of NRC Information Notice 90-65, "Recent Orifice Plate Problems." The information notice discussed problems related to orifice orientation. Duquesne Light Company assumed that the problems were related to maintenance, and focused only on orifice plates which were worked after initial installation. In retrospect, this focus was too narrow; however, it was not unreasonable based on the information in the information notice.

Unit 2 AFW System

Overall, the material condition and housekeeping in the vicinity of the AFW system was excellent. During the walkdown, the licensee conducted a quarterly surveillance test of the turbine driven AFW pump. The AFW pump started smoothly and operated well. The inspector reviewed the surveillance procedure to ensure that the system was properly restored to the normal standby condition. During the surveillance test, an issue was raised concerning in-service testing. Documentation of this issue is in Section 3.3 of this report.

2.3 Inadvertent Deactivation of Containment Isolation Signal at Unit 2 (Violation 50-412/93-30-01) (Closed)

On January 25, 1994, the licensee received a violation (50-412/93-30-01) for inadvertently deactivating the phase 'A' containment isolation signal to two containment isolation valves (2PAS*SOV105A2 and 2CVS*SOV102). Although low in safety significance, the violation was cited because it was a repeat occurrence. The licensee's response to the violation was dated February 24, 1994, and stated that the cause was inadequate corrective actions for the previous violation. The licensee failed to permanently caution tag a breaker which did not correctly identify all of its associated loads. The licensee took or committed to the following corrective actions to prevent recurrence of the violation: (1) Permanent caution tags identifying the associated loads were placed on the breaker cabinet. The opposite train breaker for associated backup containment isolation valves had the same deficiency, and was also tagged. (2) The event was scheduled for discussion in licensed operator retraining. (3) The Independent Safety Evaluation Group was tasked to perform a review of containment isolation circuits to identify any other vulnerabilities of this type. The inspectors reviewed the licensee's response to the violation and observed that the permanent caution tags were appropriately placed. The corrective actions were considered appropriate. This violation is closed.

2.4 Failed Locking Device on Unit 2 Charging Pump Suction Valve

During a walkdown of the Unit 2 high head safety injection system, the inspectors identified that the chain locking device was broken for charging pump suction isolation valve 2CHS-MOV8130A. This valve is normally locked and deenergized in the open position. This valve is closed per emergency operating procedures to split the charging system headers if the A and C charging pumps are the operable pumps. This provides a redundant recirculation flow path after transfer to cold leg recirculation.

Investigation of this issue revealed that the chain had been routed through the valve yoke and under the position indicator. Thus, when the valve was stroked on October 12, 1993, the chain was stressed until failure. The broken chain link was found on the ground below the valve operator. The licensee has completed a magnetic particle examination of the valve operator and valve yoke. No indications were identified. Engineering also completed a loading analysis of the valve based on the chain breaking strength. Engineering concluded that the valve operator did not experience thrust beyond its rating. However, it was possible that the valve stem could have experienced an applied load to cause bending. To evaluate this possibility, a dye penetrant check of the valve stem was completed and the stem was checked for straightness. No deficiencies were identified with the valve stem. The valve was also satisfactorily stroked manually and electrically. A basis for continued operation had also been developed before the above evaluations and examination were completed.

Operating personnel had two previous occasions to identify the broken chain. On November 11, 1993 and February 7, 1994, surveillance test OST2.48.7, "Padlock Valve Quarterly Review," was completed without identifying the broken locking device on 2CHS-MOV8130A. The inspector did note, however, that the end links of the broken chain were secured onto bolts on the actuator housing and made the valve appear to be properly locked unless closely inspected. The licensee is attempting to determine if the chain was so arranged intentionally. Additionally, the licensee is evaluating this issue for reportability, since technical specifications require that non-locked safety injection valves be verified in their correct position every 31 days.

The inspectors concluded that since the valve was maintained deenergized and open, there was little safety impact. The basis for continued operability properly addressed the respective operability issues. The valve was thoroughly examined for damage. The failure of operators to previously identify this deficiency indicates the need for better attention to detail.

2.5 Unit 2 Control Room Deficiencies

The inspectors reviewed Unit 2 control room deficiencies (caution tags, out-of-service stickers, and annunciators) and had the following observations:

- Component cooling water flow indicator (2CCP-FI-106A) for reactor coolant pump P-21A lower bearing lube oil cooler was noted by the inspector as being off-scale high (*i.e.*, >10 gpm). Flow normally ranges between 8.5 to 9.0 gpm. The inspectors were originally informed that flow had been set at >10 gpm. The shift supervisor subsequently identified that MWR 29206 had previously been written due to a suspected failed flow transmitter. No out-of-service sticker was, however, affixed to the flow indicator to alert operators of this condition.

- Out-of-service stickers were affixed to annunciators A6-H9, H10, H11 (steam flow >feed flow) and indicated that the associated knife switches were open. These knife switches were opened due to spurious alarm spiking during the unit startup in December 1993. These annunciators were returned to service on February 2, 1994, following troubleshooting, but operators were unaware of this fact since the out-of-service stickers remained. These annunciators provide operators with indication of a steam flow transmitter failing high, a feed flow transmitter failing low, or a steam flow - feed flow mismatch, and would in turn result in operators taking manual control of the respective feedwater regulating valve. However, operator action could have been delayed if one of these scenarios occurred since operators believed these annunciators were removed from service. The licensee has subsequently removed the out-of-service stickers since the knife switches are closed, and the alarm function was operable.

- The inspectors have noted that the annunciator for "Vital Bus Inverter Trouble" has been in an alarm condition repeatedly during the inspection period. Specifically, uninterruptible power supplies 2-3 and 2-4 have been in alarm due to the alternate power supply voltage being out of limits. Operators have been able to reset this alarm with only limited success. This alarm has become a "nuisance" alarm and will mask other alarm conditions (in the control room) for the same inverter since the annunciator will not reflash for the inverter already in alarm. MWR 027096 was previously written by operations, but voided by the instrumentation and controls department. Based on interviews with operators, the inspectors concluded that operators have become desensitized to this annunciator. Operators would only clear this alarm once per shift during the routine tour by the auxiliary operator. The MWR has been subsequently reopened and will examine possible solutions including possibly changing the annunciator setpoint.

Overall, the inspectors considered the above conditions to be indicative of the need to maintain better oversight and control of control room deficiencies.

3.0 MAINTENANCE (62703, 61726, 71707)

3.1 Maintenance Observations

The inspectors reviewed selected maintenance activities to assure that: the activity did not violate Technical Specification Limiting Conditions for Operation and that redundant components were operable; required approvals and releases had been obtained prior to commencing work; procedures used for the task were adequate and work was within the skills of the trade; activities were accomplished by qualified personnel; radiological and fire prevention controls were adequate and implemented; QC hold points were established where required and observed; and equipment was properly tested and returned to service.

The maintenance work requests (MWRs), preventive maintenance procedures (PMPs), and relay calibration procedures (RCPs) listed below were observed and reviewed. Unless otherwise indicated, the activities observed and reviewed were properly conducted without any notable deficiencies.

MWR 29253	Clean the 1A Primary Component Cooling Water Heat Exchanger
MWR 28521	Clean Y-Strainer on the Inlet of VS-P-3A

MWR 030089 2CHS-MOV-8130A Inspection

MWR 024701 Essential Service Bus Inverter Troubleshooting

MWR 029493 Power Range Monitor N-42 Calibration

During the calibration of Unit 2 power range channel N-42, the inspectors noted that the technical specification action statement for an inoperable power range channel was not being met. Specifically, during the calibration of the delta-flux circuitry of the nuclear instrument (NI), the upper and lower neutron detectors are disconnected from the nuclear instrument drawer, making the channel in calibration inoperable. Technical Specification Table 3.3-1, action number two, states that with the number of operable channels one less than the total number of channels (*i.e.*, with one of the four channels inoperable), and with thermal power above 5 percent, operation may continue if the inoperable channel is placed in a tripped condition within 1 hour. The trip function associated with N-42 for high neutron flux and flux rate was not tripped during the observed calibration. Similar conditions also existed for the calibration of channels N-41, N-43, and N-44. It takes between 4 to 6 hours to complete each channel's quarterly calibration. The inspectors were informed that the power range channels do not have a built-in design feature to allow for these reactor trip signals to be placed in a tripped condition. Normally, if a power range channel is declared inoperable, the control power fuses are removed from the nuclear instrument drawer in order to trip the high flux and flux rate trip signals. However, the control power fuses must remain installed to complete these quarterly calibrations.

When initially informed of this situation, the licensee stated that in 1988 they had issued a technical specification interpretation allowing the practice observed by the inspectors. However, the licensee withdrew this interpretation in August of 1993, in response to a different issue described in Section 2.4 of NRC inspection report 412/93-17. Overall, the inspectors did not have a safety concern, since a minimum of three channels were always operable, and the power range trip logic continued to meet the two out of three criterion. Also, the inspectors noted that standard technical specifications would allow one NI channel to be inoperable for up to 6 hours without placing the inoperable channel in a tripped condition. At the exit meeting, the licensee stated that they had discussed their interpretation with NRC prior to implementing it in 1988. They also stated that they were investigating if it was possible to remove the control power fuses to perform part of the calibration with the channel tripped, and then to replace the fuses and complete the remainder of the calibration within the 1 hour allowed by technical specifications. The inspectors will continue to follow compliance with this technical specification as an **unresolved item (412/94-07-01)**.

PMP 480VAA Motor Inspection, Lubrication and Linestarter Inspection (for QS-P-1B)

PMP ITE 5KV Air Circuit Breaker Inspection

This preventive maintenance procedure was performed on the Unit 1 '2A' outside recirculation spray pump supply breaker. The procedure was an Issue 4 version, which was well written and easy to use. The electrical maintenance supervisor had done a good job of marking the procedure to indicate what sections were not applicable to this particular breaker. The technicians demonstrated excellent use of the procedure and self-checking techniques during the maintenance activity.

RCP Calibration of Westinghouse/ABB Overcurrent Relays, Type COM-5

This procedure was used to check and set the calibration of the overcurrent relays associated with the supply breaker for the 1C primary component cooling water pump. The technicians involved with the activity demonstrated a detailed understanding of the construction and operation of the relays. Overall, use of the procedure was very good; however, the inspectors did note that the Jumper/Lifted Lead Log was not completed after removal of the relays from the cabinet. This was pointed out to the technicians, and the oversight was corrected immediately.

3.2 Surveillance Observations

The inspectors witnessed/reviewed selected surveillance tests to determine whether properly approved procedures were in use, details were adequate, test instrumentation was properly calibrated and used, technical specifications were satisfied, testing was performed by qualified personnel, and test results satisfied acceptance criteria or were properly dispositioned. The operational surveillance tests (OSTs) and maintenance surveillance procedures (MSPs) listed below were observed and reviewed. Unless otherwise indicated, the activities observed and reviewed were properly conducted without any notable deficiencies.

OST 1.30.2	R.P. River Water Pump 1A Test
2OST 1.11B	Safeguards Protection System Train 'A' SIS Go Test (see Section 3.4)
2OST 2.26.1	Turbine Governor/Throttle Valve Test
1MSP-24.10-I	F-FW476, Loop 1 Feedwater Flow Channel IV Test
1MSP-26.02-I	P-447 Turbine 1st Stage Pressure Channel IV Test

During the performance of this procedure, the inspectors noted that the technicians, with permission from their supervisor, skipped one step of the procedure. The step outlined the method of hooking up a specific piece of test equipment. The technicians and their supervisor explained that they were using the test equipment in a similar manner, which they felt was more reliable. The inspectors agreed that the change appeared to be "non-intent," but thought that such changes required a field revision to the procedure. This issue was researched and discussed with the Instrumentation and Controls Director. The inspectors found that Section 4.9 of the Maintenance Programs Unit Administrative Manual could be misinterpreted to allow "non-intent" procedure changes involving test or maintenance techniques without a field revision; however, management expectations are to the contrary. The Instrumentation and Controls Director stated that he would relay his expectations concerning procedure changes to his department.

3.3 In-service Testing Program

During the performance of a quarterly surveillance test of the Unit 2 turbine driven auxiliary feedwater (AFW) pump, the inspectors observed that the in-service test (IST) ranges were revised with no corresponding overhaul or major maintenance associated with the pump. Additionally, upon review of the Unit 1 low head safety injection (LHSI) pump surveillance test, the inspectors noted that the surveillance test did not ensure that pump flow was within a specified range of its reference value.

The licensee indicated that the IST surveillance were revised based on a change in their interpretation of IST requirements. Previously, they trended both pump differential pressure and flow. They now establish a fixed pump flow and trend pump differential pressure. Based on the inspector's review, the licensee appropriately established new alert and required action ranges for the AFW pumps.

With regard to the LHSI pumps, the surveillance did not specify a value for pump flow before taking IST data. Instead, pump flow was assumed to be the same as the reference value, because the test was conducted with the minimum flow valve full open. However, review of the previous surveillance data indicated that, on four occasions, deviations in excess of 2 percent had occurred in indicated flow. The licensee stated that the surveillance will be changed to ensure that flow is within 2 percent of the required reference value. Additionally, the licensee reviewed other procedures to ensure that flow is within 2 percent of the reference value prior to taking IST data.

The LHSI pump surveillance procedure was revised on March 1, 1994, and had been performed once since the revision. During that test, pump flow was within 2 percent of the reference value. The inspector concluded that the licensee's review of the procedure change, including the review by the onsite safety committee, was weak.

3.4 Unit 2 Engineered Safety Feature (ESF) Actuation

On March 15, 1994, during the performance of solid state protection system (SSPS) slave relay actuation testing on Unit 2, an inadvertent ESF actuation occurred. This resulted from the manipulation of the incorrect test switch by a licensed operator. Per the surveillance test 2 OST 1.12B, the operator was to have actuated test switch S826 for train 'B' testing of the 'C' service water pump breaker. Instead, the operator unlocked and opened the train 'A' SSPS test cabinet and actuated train 'A' test switch S826. This resulted in the start of the train 'A' containment hydrogen analyzer. Following this inadvertent ESF actuation, the start signal was reset and the hydrogen analyzer was secured. The inspectors reviewed this event and noted that both trains of SSPS test cabinets were properly labeled on the interior and exterior. Causal factors of this event include the fact that the operator had previously completed SSPS testing on the 'A' train. Also, the test cabinet keys are not labeled and the keys for both trains are on the same key ring. A human performance root-cause evaluation is currently in progress by the licensee. Corrective actions thus far include enhanced labeling and operator training. The inspectors did not have any safety concerns regarding the start of the hydrogen analyzer.

On April 11, during SSPS testing of relays K603A and K603XA, containment air recirculation fan (2HVR-FN201A) failed to trip as expected. Investigation revealed that the fan had not been manually started by the operator prior to the test. SSPS test procedure 2OST 1.11B properly specified the need to place the containment air recirculation fan control switch to the start position and verify that the red indicating light is on. Follow-up testing revealed proper operation of the relays. The licensee determined that a lack of communication existed between the operators performing the test. Although there were no safety implications from this second event, both events as a whole represent the need for improved attention to detail by operators.

3.5 Switchyard Access and Work Controls

On April 8, 1994, a worker opened the breaker for the switchyard relay room fire alarm and lights while attempting to deenergize a water heater he was working on. The worker had obtained authorization for the water heater work, but he was not authorized to open any breakers. This condition was alarmed in the Unit 1 control room, and it was quickly corrected by closing the breaker and stopping work in the switchyard. Although this event did not cause any serious problems, it did show that the controls placed on switchyard work following the October 12, 1994 loss of offsite power event were not adequate. By night order dated April 8, 1994, the licensee strengthened these controls to require that prior authorization for such work be approved by the Vice President of Operations. The inspectors concluded that this additional control appears adequate; however, it is only temporary. The licensee stated that they expect to finalize their long-term switchyard access and work controls in a few weeks.

4.0 ENGINEERING (71707, 90712, 92700)

4.1 Review of Written Reports

The inspectors reviewed Licensee Event Reports (LERs) and other reports submitted to the NRC to verify that the details of the events were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspectors determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted further onsite follow-up. The following LERs were reviewed:

Unit 2:

94-01 "Refueling Water Storage Tank Lo-Lo Level Transmitters Freezing"

This event was discussed in detail in Inspection Report 50-412/94-02. The inspectors noted one error in the licensee's description of the event. The LER states that they entered Technical Specification (TS) 3.0.3 at 8:20 a.m. They actually entered this TS at 9:20 a.m. The licensee had two potentially inoperable level transmitters at 8:20 a.m., but did not enter TS 3.0.3 because they had reasonable indications that one of the two transmitters had returned to an operable status (the low-low level alarm had cleared). At 9:20 a.m., testing showed that the transmitter with the cleared low-low level alarm was still inoperable. This forced the licensee to enter TS 3.0.3, and led to the start of the power reduction a 9:42 a.m. The inspector did not have any more comments concerning this report.

93-16 "Inadvertent Deactivation of CIA Signal From Two Containment Isolation Valves"

The issues associated with this LER are discussed in Section 2.3 of this report. The inspectors had no further comments.

The above LERs were reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. Generally, the LERs were found to be of high quality with good documentation of event analyses, root cause determinations, and corrective actions.

4.2 Safety Related Heat Exchanger Performance Monitoring

The Unit 1 river water and the Unit 2 service water systems are designed to transfer heat from various components to an ultimate heat sink (the Ohio River). The licensee is required by 10 CFR Part 50, Appendix B to have a test program which demonstrates that these systems will perform satisfactorily in service (which includes design basis conditions). The inspectors reviewed the portions of this test program pertaining to the performance of heat exchangers. Some of this review involved comparison of the current performance monitoring program to the licensee's commitments provided in their response to Generic Letter 89-13 "Service Water System Problems Affecting Safety-Related Equipment."

The licensee's heat exchanger performance monitoring primarily involves one or more of the following for each heat exchanger: (1) Measurement of the heat exchanger's fouling factor with comparison to a calculated operability limit. The operability limit varies as a function of temperature. Heat exchanger monitoring is increased if the measured fouling factor approaches the operability limit within a pre-determined limit. (2) Periodic heat exchanger cleaning. (3) Measurement of heat exchanger tube side flow and pressure drop. This evaluation method is primarily applied to room coolers and the recirculation spray heat exchangers. Action to clean a room cooler is typically required when flow or pressure drop degrade by 20 percent. The minimum flow requirement for the recirculation spray heat exchangers is specified by Technical Specifications. (4) Evaluation of an air conditioning unit's ability to maintain the temperature of the space which it is designed to cool. This is primarily applied to the control room air conditioning units and the main steam valve area coolers.

The inspectors were able to conclude that the licensee's heat exchanger monitoring program did not demonstrate that the heat exchangers would perform satisfactorily under design basis conditions. The following are the reasons for this conclusion: (1) The licensee was not able to provide documentation which validates their assumption that heat exchanger flow rates will be satisfactory under design basis conditions during an operating cycle. A full flow river water or service water test is conducted following each outage, usually after most of the significant heat exchangers have been cleaned. However, some of the heat exchangers have very little flow margin even after cleaning, and the licensee does not have documentation which shows that the margin still exists during or following the end of the cycle. (2) The licensee has no documentation related to the affects of instrumentation accuracies on test results. (3) The results of the periodic heat exchanger cleaning and inspection are not thoroughly documented, in most cases. Moreover, in the case of room coolers, there is no evaluation of the heat transfer capability on the air side of the cooler. Thus, the licensee does not have a strong basis for saying that periodic cleaning is their assurance of heat exchanger operability. (4) The licensee does not have a preventive maintenance or surveillance program which ensures the effectiveness of their river water screen wash system. The inspectors observed that some debris on the 'A' river water screen had passed the screen wash area and would have been carried to the inner bay where the river water pumps take suction.

In addition to the issues discussed above, the inspectors determined that the licensee had not adequately justified excluding the Unit 2 rod control/cable vault air conditioning units from the heat exchanger performance monitoring program. This problem has been rectified by the licensee. The issue is discussed in more detail in the following section of this report.

The inspector's findings were presented to appropriate Maintenance Engineering and Assessment Department managers and engineers. The licensee agreed that they need to establish a better program for evaluating the "as-found" condition of a heat exchanger when it is opened for cleaning, and stated that they are going to enhance their current program. This enhancement will include evaluation of the condition of the air side of room coolers. The licensee also agreed that they need to evaluate the affect of instrument tolerances on the accuracy of test results, and stated that they would do such an evaluation. The licensee agreed that degraded performance of the screen wash system can affect system operability, and stated that they would evaluate their preventive maintenance and surveillance program for improvements. The licensee is currently evaluating the adequacy of heat exchanger flow verification. The issue of heat exchanger flow verification is an **unresolved item (50-334/94-07-02 and 50-412/94-07-02)** pending review of the licensee's evaluation.

4.3 Unit 2 Cable Vault Environmental Qualification

The rod control/cable vault air conditioning units at Unit 2 were originally designed to maintain the associated area temperatures less than 120°F. 120°F is the environmental qualification (EQ) limit for the cable vault areas. The normal cooling water supply to these units is from the chilled water system. However, the chilled water system is not safety related, and the service water system is required to maintain cooling to the units following a loss of offsite power (LOOP). In 1990, the licensee determined, through engineering calculations, that the supplemental leak collection and release system (SLCRS) could maintain sufficient air flow in the cable vaults, following a LOOP, to maintain temperatures below the EQ limit. Following this determination, the licensee removed the rod control/cable vault air conditioning units from the heat exchanger monitoring program, and isolated service water from the units.

During an inspection of the licensee's heat exchanger performance monitoring program (see Section 4.2 of this report), the inspectors reviewed the cable vault EQ calculation, and realized that the licensee did not have EQ performance criteria for SLCRS air flows in the cable vaults. Additionally, the inspectors noted that the total SLCRS air flow out of the cable vaults was less than the required air flow in the EQ calculation. These findings were presented to the SLCRS System Engineer, who initiated an evaluation of the situation. The licensee's calculations showed that the peak temperatures in the east and west cable vaults following a LOOP, based on the as-found SLCRS flow rates, would have been 148 and 237°F, respectively. These calculations were based on a design basis outside temperature of 90°F. Additional calculations showed that peak temperatures following a LOOP with the existing outside air temperature of 60°F would have resulted in less than 120°F in the east cable vault and about 180°F in the west cable vault.

Based on the second calculation, the licensee declared the components in the west cable vault inoperable and entered a 6-hour Technical Specification action statement for the most limiting components - two trains of auxiliary feedwater flow control valves. During the 6-hour period, the licensee was able to adjust SLCRS flows in the cable vaults to meet EQ requirements. The licensee made a one hour non-emergency report to the NRC because of plant operation outside its design basis.

The licensee has reevaluated the east cable vault EQ calculations and determined that the heat loads were unnecessarily conservative. By considering only those loads which are continuously energized, the licensee determined that the east cable vault would not have reached 120°F following a LOOP with the original SLCRS flows. The licensee is still validating these calculations and will also reanalyze the calculations for the west cable vault.

Additionally, a root cause analysis is in progress to determine why this situation occurred. The issue of equipment EQ in the cable vaults is an **unresolved item (50-412/94-07-03)** pending review of the licensee's updated calculations and their root-cause analysis.

4.4 Unit 1 Feedwater Flow Control Valve Deficiency

On March 15, 1994, the System Engineer responsible for the main feedwater system identified a broken bolt on the actuator of one of the Unit 1 feedwater flow control valves. With one bolt broken, the remaining bolts assumed additional load, and were, therefore, more likely to fail. Failure of more than one of the actuator bolts could have presented a significant challenge to controlling steam generator water level. The licensee promptly reduced reactor power to approximately 32 percent and repaired the valve. As a long term corrective action, the licensee is going replace the flow control valve actuators with units that have less susceptibility to this type of failure. The replacement is scheduled for the next refueling outage. The inspectors looked at the broken actuator bolt just after it was identified. The deficiency was extremely hard to see, and would not have been recognized without a detailed understanding of the actuator's construction and potential failure mechanisms. The inspectors concluded that: (1) the recognition of this sort of deficiency indicates a strength in the system engineering program; and (2) the licensee's actions to address the deficiency were appropriate and very timely.

5.0 PLANT SUPPORT (71707, 90713)

5.1 Radiological Controls

Posting and control of radiation and high radiation areas were inspected. Radiation work permit compliance and use of personnel monitoring devices were checked. Conditions of step-off pads, disposal of protective clothing, radiation control job coverage, area monitor operability and calibration (portable and permanent), and personnel frisking were observed on a sampling basis. Licensee personnel were observed to be properly implementing their radiological protection program.

5.1.1 High Radiation Area Boundary Controls

While obtaining a sample of water from the Unit 1 spent fuel pool, an analyst reached across a high radiation area (HRA) boundary without implementing HRA controls. Placing extremities across a HRA boundary without HRA controls is not specifically prohibited by regulatory requirements (if properly controlled and evaluated), but has been discouraged by the licensee in the past.

This observation was discussed with chemistry and radiological controls personnel. The licensee stated that they still discourage the practice of reaching across HRA boundaries without full HRA controls, and they intend to take further action to ensure that station personnel understand their position.

5.2 Chemistry Boron Analysis Training

During the period, the inspectors attended a training session on boron analysis. The training was a result of a Quality Services Unit assessment of boron analysis. The assessment was requested by the Chemistry Department because of slight variations in analysis results between analysts. The variations were not significant, but did not meet the licensee's expectations. The assessment and the training were of high quality, and evident of a good chemistry program with strong, conservative management expectations.

5.3 Security

Implementation of the physical security plan was observed in various plant areas with regard to the following: protected area and vital area barriers were well maintained and not compromised; isolation zones were clear; personnel and vehicles entering and packages being delivered to the protected area were properly searched and access control was in accordance with approved licensee procedures; persons granted access to the site were badged to indicate whether they have unescorted access or escorted authorization; security access controls to vital areas were maintained and persons in vital areas were authorized; security posts were adequately staffed and equipped, security personnel were alert and knowledgeable regarding position requirements, and that written procedures were available; and adequate illumination was maintained. Licensee personnel were observed to be properly implementing and following the Physical Security Plan.

5.4 Housekeeping

Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards. The inspectors conducted detailed walkdowns of accessible areas of both Unit 1 and Unit 2. Housekeeping at both units was acceptable.

5.5 Incore Detector Traceability Special Report

By a special report dated March 4, 1994, and by a telephone notification, the licensee reported that five moveable incore detectors could not be traced from receipt to final disposition. One of the missing detectors was subsequently found in storage. The four detectors that remain unaccounted for could contain at most a total of 0.0164 grams of U235.

The inspectors reviewed the licensee's investigation and found that the licensee had done an extensive review of purchase orders, nuclear material records, maintenance work requests, and records of radioactive waste shipments in an attempt to determine the final disposition of all 55 detectors received since 1976. The licensee did not treat incore detectors as special nuclear material until 1986. The licensee concluded that the four missing detectors were irradiated and removed from service prior to 1986, and that they were disposed of as radioactive waste. The inspectors reviewed the licensee's current controls of special nuclear material and found that they provided adequate accountability for all remaining incore detectors.

6.0 ADMINISTRATIVE

6.1 Preliminary Inspection Findings Exit

At periodic intervals during this inspection, meetings were held with senior plant management to discuss licensee activities and inspector areas of concern. Following conclusion of the report period, the resident inspector staff conducted an exit meeting on April 20, 1994, with Beaver Valley management summarizing inspection activity and findings for this period.

6.2 Attendance at Exit Meetings Conducted by Region-Based Inspectors

During this inspection period, the inspectors attended the following exit meetings:

Dates	Subject	Inspection Report No.	Reporting Inspector
4/08/94	Safety Related Check Valves (TI 110)	94-09/09	F. Bower
4/08/94	EDSFI Follow-up (TI 111)	94-10/10	N. Della Greca
3/18/94	OSTI	94-80/80	J. Trapp

6.3 NRC Staff Activities

Inspections were conducted on both normal and backshift hours: 29 hours of direct inspection were conducted on backshift; 17 hours were conducted on deep backshift. The times of backshift hours were adjusted weekly to assure randomness.

J. Linville, Chief, PB3, visited the inspectors and toured the site on April 18 and 19.

R. Barkanic, Pennsylvania Department of Environmental Resources, visited the inspectors on April 7 and discussed inspection activities and the licensee's performance.

J. Durr, Deputy Director, DRP, visited the inspectors and toured the site on March 23 and 24.