U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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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:	January 4 - February 7, 1994
Inspectors:	Lawrence W. Rossbach, Senior Resident Inspector Peter P. Sena, Resident Inspector Scot A. Greenlee, Resident Inspector Daniel Moy, Reactor Engineer

Approved by: _____ 3/1/94
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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.

EXECUTIVE SUMMARY

Beaver Valley Power Station
Report Nos. 50-334/94-02 & 50-412/94-02

Plant Operations

The Unit 1 plant startup was well controlled with good management oversight. Plant safety was appropriately maintained as the clear priority while the need for additional electrical generating capacity existed due to record cold weather. Operator response to a feedwater transient precluded a potential plant trip. Minor reactor coolant system (RCS) leakage into the vessel head vent system has been experienced following plant startup. Corrective actions are being evaluated.

Unit 2 has experienced high pressure in the residual heat removal system (RHR) since December 1993. Unit 1 is not experiencing any RCS leakage into the low pressure RHR system. The source of the Unit 2 in-leakage is believed to be due to the 'C' safety injection accumulator. The safety significance of the leakage is low, and the licensee has adequate procedures to detect and address any increase in leakage. In-service testing of the Unit 1 and Unit 2 pressure isolation valves, with one exception, has provided assurances of their leak-tight integrity as independent barriers against abnormal reactor coolant pressure boundary leakage.

Both units have experienced freezing problems due to the extreme cold weather. Two Unit 2 refueling water storage tank level transmitters were rendered inoperable and resulted in the initiation of a technical specification required shutdown. The shutdown was secured at 94 percent when the transmitters were restored to operable status. Unit 2 has a history of freezing problems.

The licensee's actions to correct deficiencies in the operating manual change process have been effective.

Maintenance

Inadequacies in the maintenance planning process continue to be identified. A review of the lubrication program identified that some safety-related components were omitted. This led to degradation of a bearing on a supplemental leak collection and release system blower.

Although a solenoid operated valve (SOV) task force was recently appointed to examine repetitive problems with SOVs, questions remain regarding evaluation and/or implementation of recommendations made in NUREG 1275, Volume 6, "Operating Experience Feedback Report - Solenoid Operated Valve Problems," in 1991.

The licensee took action to improve timeliness of post-maintenance ASME required visual exams.

Executive Summary

Engineering

As a result of repetitive problems with frozen components in the refueling water storage tank (RWST) enclosure at Unit 2, control bands for several heat trace circuits were revised. Overall short term corrective actions for frozen component problems in the Unit 2 RWST enclosure were comprehensive and conservative.

Corrective action in response to the degradation of the Unit 2 reactor coolant system (RCS) resistance temperature detectors was determined to be satisfactory. The licensee was found to have adequate procedures and equipment to monitor RCS temperature and water level in mid-loop and reduced inventory conditions.

Plant Support

The inspectors identified one instance in which a worker failed to perform a required whole body frisk after leaving a radiologically controlled area. The worker's failure to frisk was a violation, but was not cited because of the low safety significance, the isolated nature of the occurrence, and the licensee's comprehensive corrective actions.

The inspectors also noted that a chemistry technician failed to perform the final steps of a boron analysis procedure. This was also a violation, but, again, was not cited because of the low safety significance, the isolated nature of the occurrence, and the licensee's comprehensive corrective actions.

The licensee identified two instances where they were slow to comply with site fire protection requirements in safety-related areas.

On January 9, 1994, the licensee declared an Unusual Event because of a technical specification required plant shutdown at Unit 1. All required notifications were properly completed. The event was terminated on January 10.

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DETAILS

1.0 MAJOR FACILITY ACTIVITIES

Unit 1 operated at full power until January 9 when an Unusual Event was declared and the licensee shut the unit down due to inadequate flow through the recirculation spray heat exchangers. This event is described in more detail in Sections 3.3 and 5.3 of this inspection report. The unit was brought critical on January 19, after cleaning of the heat exchangers. The unit operated at full power from January 20 to January 23 when power was reduced to 63 percent due to low feedwater pump suction pressure. This is described in more detail in Section 2.3. The unit was returned to full power on January 24 and operated at full power for the remainder of this inspection period.

Unit 2 operated at full power throughout this inspection period except for a power reduction to 94 percent power on January 15 due to the freezing of several refueling water storage tank level sensing lines. This is discussed in more detail in Sections 2.7 and 4.3.

2.0 PLANT OPERATIONS (71707, 93702, 71714)

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 walk-downs of the following systems: quench spray sodium hydroxide addition; refueling water storage tank piping and heat trace; main steam supply and drains to the steam driven auxiliary feedwater pump; and recirculation spray. 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 Structures
- Yard Areas
- Containment Penetration Areas
- Unit 1 Containment Building

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.

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. Postings of notices to workers were also reviewed.

2.2 Unit 1 Plant Startup

The inspectors observed the Unit 1 plant startup and reviewed the technical specification prerequisites necessary for mode changes. All required prerequisites were properly tracked and completed by the licensee within the specified intervals. The inspectors also completed an estimated critical position (ECP) calculation and verified that the ECPs completed by the reactor engineer, shift supervisor, and shift technical advisor were within proper agreement. The reactor startup was designated as an "infrequently performed test or evolution" and was thus given additional management oversight by the Unit 1 operations manager. Plant safety and the need for maintaining a questioning attitude were appropriately stressed. Very good coordination was evident between the four licensed reactor operators on shift during the rod withdrawal sequence. The extra operators assisted with the inverse count rate (1/m) approach to criticality plot and completed various technical specification surveillances. These activities included shutdown margin checks every hour and verifying reactor coolant temperature and pressure were on the correct side of the criticality curve every 15 minutes. This coordination and assistance thus allowed the reactor operator at the controls to follow each reactivity manipulation cautiously and thus pay strict attention to the effects of the reactivity changes in the core.

The reactor startup was conducted on the morning of January 19, 1994. Due to severe arctic weather and its associated record cold, a Statewide Disaster Emergency was declared by the Governor of Pennsylvania that morning. Peak electrical demands resulted in some utilities initiating nonvoluntary rotating local blackouts to maintain grid stability. Although the urgent need for additional electrical generating capacity was known by the operating staff, reactor safety was appropriately maintained as the clear priority. The plant startup was completed safely and methodically without any external influences. Overall, the inspectors considered the management oversight of the reactor startup and the emphasis on plant safety to be a strength.

2.3 Unit 1 Feedwater System Transient

On January 23, 1994, with the unit at 100 percent power, a main feedwater pump low suction pressure alarm was received. Operators responded properly to reduce reactor power and were able to avoid a feedwater pump trip. The inspectors reviewed the sequence of events recorder, interviewed personnel on the operating shift, and concluded that operator response was good and precluded a potential plant trip and challenges to safety systems.

Failing to confirm a suspected malfunction in the heater drain tank level controllers, operators returned the plant to 100 percent power while continuously monitoring the level controllers. Subsequent investigation revealed that condensate pump discharge pressure was trending down prior to receipt of the feed pump suction pressure alarm, but condensate flow remained constant, thus indicating a diversion of condensate flow. The possibility of a malfunction in the main condenser hotwell level control system is being evaluated by the licensee. Meanwhile, feed pump suction pressure and condensate discharge pressure are being closely monitored to allow operators ample time to respond if the situation repeats.

2.4 Unit 1 Head Vent Valve Seat Leakage

Following the reactor startup, the plant experienced minor reactor coolant leakage into the reactor coolant gas vent system. Per the alarm response procedure, operators are currently venting the pressurized gas vent piping to the pressure relief tank (PRT) about every 12 hours when pressure reaches 2,000 psig.

Two containment entries were made in an attempt to identify and isolate the pilot and solenoid valves leaking by. During the troubleshooting, each manual isolation valve downstream of the four SOVs was shut in various configurations. The licensee determined that at least two of the SOVs from either the vessel head or pressurizer were leaking by. Additionally, the downstream vent valve to containment atmosphere or the vent valve to the PRT (SOV-RC-104) was determined to be leaking by. Containment atmosphere radiation monitors have not detected any increase in activity. No detectable in-leakage to the PRT has been noted. Identified leakage remained at 0.114 gpm with RC-SOV-104 open or shut. The licensee's engineering staff is currently performing an evaluation to determine if the head vent line can remain pressurized to eliminate the need for further cycling of RC-SOV-104.

Although the source of the leakage has not been positively identified, each valve manipulation, technical specification entry, and initial conditions were properly logged by the shift supervisor in order to assure proper system restoration and maintain a documented history of the troubleshooting. The inspectors had no further concerns in this area.

2.5 Unit 1 Pressure Isolation Valves

A review of the Unit 1 residual heat removal (RHR) system design, surveillance testing, and procedures was completed by the inspectors to determine if the unit is operating, or has a high potential to operate in a degraded condition relative to leakage past the pressure isolation valves in a high-to-low pressure interface system. The RHR system is located entirely inside containment, so personal monitoring for increased piping surface temperatures to detect reactor coolant system leakage is impractical.

In-service testing of the 12-inch discharge checks (SI-52 and 53) to reactor coolant cold legs 2 and 3 is accomplished every refueling outage, after maintenance, and each time the plant is placed in cold shutdown if testing has not been accomplished in the proceeding 9 months. Operational Surveillance Test 1.11.04A was reviewed, and zero leakage past SI-52 and 53 was noted on January 13, 1994. On April 7, 1993, SI-53 did have a slight leakage rate of .88 gpm; however, technical specifications allow up to a 5 gpm leakage rate. The RHR suction isolation valves are 14-inch gate valves (MOV-RH-700 and 701). Leak testing of these valves was conducted during the last refueling outage. The leakage rates of MOV-RH-700 and 701 were .273 gpm and .126 gpm respectively, and were within the 5 gpm technical specification limit.

Generic Letter 87-06, "Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves," indicated that plant technical specifications should include a list of all pressure isolation valves (PIVs) along with a description of testing methods. The PIVs are defined as any two valves in series within the reactor coolant pressure boundary which separates the high pressure coolant system from the attached low pressure system. The 14-inch RHR discharge isolation valves (MOV-RH-720A and 720B) to reactor coolant cold legs 2 and 3 were added to plant technical specifications (License Amendment 124) following the licensee's response to the generic letter. For the testing of MOV-RH-720A and 720B, technical specification Table 4.4-3 states "leakage rate continuously monitored during plant operation, no other leakage rate testing is required." The technical specification leakage rate acceptance criteria is 5 gpm. The licensee's method of leakage rate monitoring is done by checking the status of annunciator A1-125, "RHR Pump Discharge Pressure High," every 8 hours. The unit has not had a history of receiving this annunciator while at power. The inspector verified the associated pressure switch was within calibration and properly set at 550 psig. Reliance on an annunciator (rather than a pressure indicator) to monitor system pressure as a measure of the integrity of MOV-RH-720A and 720B as an independent barrier at the reactor coolant pressure boundary is under review by the NRC.

The alarm response procedure (ARP) associated with annunciator A1-125 was also reviewed. The pressurizer relief tank pressure and level indicators are checked to determine if the RHR system relief valve (RV-RH-721) is discharging. The relief setpoint is 600 psig, and the valve is within calibration per the in-service testing program. A reactor coolant water inventory balance is performed to quantify any leakage. It is not, however, possible to determine which specific RHR isolation valve (MOV-RH-700, 701, 720A, or 720B) may be

leaking by. The ARP refers to the reactor coolant system operational leakage technical specification (3.4.6.2) for acceptable leakage rates. The maximum identified leakage allowed by the technical specifications is 10 gpm. However, the more limiting acceptance criteria is 5 gpm for a single PIV per Technical Specification 3.4.6.3. The licensee has subsequently processed an operating manual change notice to incorporate the more limiting technical specification into the ARP. The inspectors did note that this ARP had already been processed through the licensee's procedure upgrade program.

Overall, the inspectors found that Unit 1 is not and has not operated with any significant leakage into the RHR system. Slight leakage into the RHR system, however, may not be readily identifiable if RHR system pressure reached equilibrium below the high pressure annunciator setpoint of 550 psig. Increased reactor coolant leakage would be detectable through the water inventory balance. In-service testing of the PIVs, with the exception of MOV-RH-720A and 720B, has provided assurances of their leak tight integrity as independent barriers against abnormal reactor coolant leakage. The ARP was viewed as adequate, with the exception of referencing a less conservative technical specification leakage rate acceptance criteria.

2.6 Unit 2 Residual Heat Removal System Isolation Valve Leakage

Beaver Valley Unit 2 has experienced abnormally high pressure of 280 to 380 psig in train 'B' of the residual heat removal (RHR) system since the end of the last refueling outage (December 1993). Unit 2 has pressure indicators in the control room which provide continuous indication of RHR system pressure. The licensee believes that the abnormal pressure is due to minor leakage from the 'C' loop safety injection (SI) accumulator into the RHR system (past the RHR system discharge, motor operated, isolation valves). The 'C' SI accumulator leak rate is tracked by the licensee, and has been a maximum of .01 gallons per minute.

The inspectors evaluated the abnormal RHR system pressure to: (1) determine the likelihood that the problem was due to leakage from the reactor coolant system (vice the SI accumulator); (2) bound the magnitude of leakage into the system; (3) evaluate the licensee's actions to monitor and correct the problem; (4) determine the adequacy of the licensee's procedures for dealing with the problem; and (5) determine the overall safety significance of the problem. Specifically, the inspectors: reviewed the design of the system; reviewed the surveillance test history for all RHR system isolation valves; reviewed the licensee's procedures for monitoring RHR system pressure; reviewed the licensee's procedures for high pressure in the RHR system; and discussed the problem with the Unit 2 Operations Manager and several plant operators.

The inspectors concluded that it is very likely that the source of leakage is the 'C' SI accumulator. The leakage is conservatively estimated at less than .22 gallons per minute based on the total calculated leakage from the reactor coolant system (RCS) plus leakage from the 'C' accumulator. The licensee's actions for the problem have been to monitor RHR

system pressure and the leak rate from the 'C' SI accumulator. Based on the minor magnitude of the leakage and the relatively stable RHR system pressures, these actions were considered acceptable. Additionally, if any increase in leakage is detected, the licensee will consider increasing the seating torque on the system isolation valves.

A licensed operator logs RHR system pressures once a shift. If pressure on either train exceeds 425 psig, actions are required to determine the source of the leakage, and evaluate leakage for compliance with Technical Specifications. The level of monitoring and procedural guidance should be sufficient to detect and take actions for any increase in leakage.

The overall safety significance of the leakage into the RHR system is low. The current magnitude of the leakage is low, and the licensee has adequate procedures in place to detect and address any increase in leakage. Additionally, the RHR system at Beaver Valley Unit 2 is completely contained within the containment building. Thus, a loss of coolant accident from the RCS to the RHR system is much less risk significant than at other plants where the RHR system extends outside of the containment building.

2.7 Cold Weather Preparations and Problems

Cold weather preparations at Beaver Valley are verified by the performance of operating surveillance tests (OSTs) entitled "Cold Weather Preparation Verification." These OSTs were performed at both units between October and December 1993. No significant problems were encountered during the OSTs, which included checking the station heat trace systems.

On January 5, 1994, the licensee encountered their first significant problem due to cold weather. Following the performance of routine preventive maintenance on a Unit 2 quench spray pump (2QSS*P21A), the licensee attempted to run the pump's quarterly OST to verify operability. They were unable to obtain any flow through the pump because the pump test line was blocked by ice. The test line heat trace system indicated satisfactory operation (i.e., the line temperature sensor indicated that temperature was above freezing). The licensee found that the insulation around the frozen section of pipe was wet, which made the heat tracing in that area ineffective. The wet insulation was removed, and temporary heat was applied to the frozen section of pipe. The licensee was able to run the OST prior to exceeding the Technical Specification (TS) allowed outage time for one quench spray pump. The safety significance of the event was low since the quench spray pump test line is not used during accident conditions, and all safety equipment was maintained operable within the requirements of TS. Following this event, the licensee replaced the heat trace cable and insulation on the test line. Additionally, they took the opportunity, while the insulation was removed from the test line, to add an installed spare heat trace cable.

On January 14 and 15, the licensee experienced their second significant problem due to cold weather. This time, they experienced problems with freezing on three of the four Unit 2 refueling water storage tank (RWST) level transmitters in the engineering safety features

actuation system (indicated by an RWST extreme-low level alarm). In each case, the heat trace circuits indicated satisfactory operation. The licensee's short term corrective actions included adding jumpers to the associated heat trace circuits to make them operate independently of the heat sensing elements, and establishing temporary heating in the RWST enclosure. The performance of the heat trace circuits and the electrical output of the level transmitters was then closely monitored, and kept within prescribed bands by manually cycling the heat trace circuit power isolation breakers. This action corrected the freezing problem, but not before two of the level transmitters became inoperable at the same time. This condition was identified at 9:20 a.m. on January 15. TS only allow one of the four transmitters to be inoperable at one time (except for a one hour period which may be used for testing). Consequently, the licensee commenced a plant shutdown at 9:42 a.m. The NRC was notified of the shutdown at 10:00 a.m. At 10:46 a.m., the extreme-low level alarms associated with the frozen transmitters cleared. At this point, with indications of transmitter operability, the licensee placed a hold on power reduction (with power at 94.5 percent). At 12:02 p.m., operability of the transmitters was verified and the shutdown was officially terminated. The NRC was notified of the shutdown termination, and the plant was returned to 100 percent power.

The inspectors reviewed records and interviewed personnel concerning the sequence of events on 14 and 15 January. The inspectors concluded that the licensee complied with the TS and reporting requirements. However, there was considerable licensee confusion concerning the interpretation of the TS, and how to determine RWST level transmitter operability. The safety significance of event was low—with two inoperable transmitters in bypass, the remaining two transmitters would be available to initiate the recirculation mode of safety injection during an accident. If more than two transmitters had failed, then the operators would have been required to manually initiate recirculation in the event of an accident in accordance with procedures. Failure of the RWST level transmitters in the extreme-low condition, even if they were not placed in bypass, would not cause a safety system actuation unless a safety injection signal was present.

The inspectors discussed these issues with the Unit 2 Operations Manager, who agreed with the inspector's conclusions and stated that he planned to review the associated TS with plant operators to ensure complete understanding of the requirements and the method of operability determination for the RWST level transmitters. The licensee's near term and long term actions to address the Unit 2 cold weather problems are discussed in Section 4.3 of this report.

The inspectors also reviewed the licensee's Unit 1 RWST piping inspection for potential freeze up. During the record cold of January 19, 1994, the RWST fill line had frozen. This was identified later in the week when operators were unable to make up to the RWST. There were no safety implications from this ice blockage. Alternate fill methods were available. A 100 percent walkdown of RWST piping and sodium addition tank piping was completed by licensee personnel. Damaged and wet insulation was found on this fill line. A contact pyrometer on the pipe surface (under the insulation) indication 40°F. About 50-60°F was

the expected temperature. The heat trace on this line was verified operable; however, the heat trace is not of sufficient capacity if the insulation is damaged or wet. Minor insulation damage discovered on the remaining RWST lines was identified during the licensee's walkdown and temporary repairs were completed. Also, a chimney was constructed around the fill line using a fire retardant plastic sheeting. An electric space heater is in place as a heat source. The Unit 1 RWST piping has not had a history of freezing. Also, the Unit 1 RWST level transmitters are of a flange mounted design and are not susceptible to freezing as were the Unit 2 transmitters. The licensee's corrective actions of inspecting the Unit 1 RWST piping for future possible freeze-up was acceptable.

2.8 Switchyard Controls

On October 12, 1993, Beaver Valley experienced a complete loss of offsite power caused by poor control of maintenance in the switchyard. As a result, the licensee implemented interim administrative switchyard controls. The final set of controls for switchyard activities is still pending. The inspectors have observed the use of these interim controls on several occasions and have noted increased awareness and control of switchyard activities. However, on one occasion, it was noted that the Unit 2 shift supervisor admitted a traveling operator (from the substation department) into the switchyard without understanding the nature of his work. The reason for this lapse in control was poor communications. The shift supervisor assumed that the traveling operator was going to work on equipment as discussed in the morning turnover meeting the day before. The shift supervisor did not, however, have the paperwork which should have accompanied such work. The work scope had changed, but the change had not been communicated to the shift supervisor. Additionally, no one from system operations contacted the shift supervisor, prior to the traveling operator's arrival, as required by the interim administrative switchyard controls. The inspectors concluded that the licensee's interim instructions for control of switchyard maintenance were good, but management attention is still needed to ensure that the controls are implemented. The inspector's observations were discussed with the Unit 2 Operations Manager. The Operations Manager acknowledged the observations, and stated he would look into the issue.

2.9 Pressure/Temperature Limitation Curve (VIO 334/93-12-01) (Closed)

This violation, involving the use of an incorrect reactor coolant system heatup limitation curve, remained open following the inspectors' identification of additional deficiencies. Specifically, out-of-date core cycle reactivity curves were found in the control room operating manual (see NRC Inspection Report 50-334/93-26). These reactivity curves are used to determine estimated critical position for reactor startup. The inspectors have subsequently re-reviewed existing controlled copies of operator aides to ensure they were accurate and of the correct revision. This included Unit 1 and Unit 2 pressure/temperature limits, rod insertion limits, core safety limits, axial flux difference limits, and tank curves. The core reactivity curves were also consistent with the Westinghouse core design report.

The licensee's original corrective actions for the violation included clarifying the method, for procedure clerks, by which operating manual change notices (OMCNs) are processed. Also, the number of people who distribute OMCNs was limited in order to maintain better accountability. The inspectors had concluded that these corrective actions in tightening the control of the operating manual change process had been ineffective as evidenced by the incorrect reactivity curves in the operating manual. The licensee subsequently identified that four additional controlled copies of the operating manual also had not been properly updated. The procedure change was incorrectly implemented by several procedure clerks in that the reactivity curves were not removed from the operating manual. The licensee determined the root cause to be a lack of clarity in the filing instructions provided by the procedure engineer. The procedure clerks had a "lack of confidence" in the accuracy of the filing instructions, and were reluctant to remove the reactivity curves since there were no referral documents to insert in their place. The licensee has held a discussion with the procedure clerks to re-emphasize that filing instructions are to be followed and discrepancies are to be identified to the procedures supervisor immediately. Also, the procedures engineers have been instructed to provide greater accuracy in the filing instructions and to use a referral page when a document is deleted.

In addition, the operating manual distribution and control process is currently being revised and will use the corporate "document control system". This action is being taken in response to Quality Assurance Audit BV-C-91-01, "Records Management and Document Control Program." This audit identified, in part, that the site document control program was not effectively implemented. The changes in progress include the development of a computerized master listing of all documents which clearly show the revision level of the documents and all outstanding temporary changes. Commencing April 1, 1994, operating manual revisions will be issued via the new document control system. The inspectors reviewed an example of the new controlled document distribution form and found it to clearly identify the document being transmitted along with the revision level and all documents to be removed. The licensee's corrective actions in response to the QA audit are adequate. This violation is closed.

2.10 Verification of Plant Records (Unresolved Item 50-412/93-14-01) (Closed)

On April 23, 1992, the NRC issued information Notice 92-30, "Falsification of Plant Records," to alert licensees to the concern that plant mechanics, technicians, and operators may have falsified plant logs at several nuclear plants. Duquesne Light Company's actions in response to this information notice were documented in NRC Inspection Reports 50-334/93-13, 50-412/93-14, 40-334/93-26, and 50-412/93-28. Unresolved Item 93-412/93-14-01 was opened pending further NRC assessment of the licensee's finding that one non-licensed operator had not properly performed his rounds. On October 15, 1993, the NRC completed its review of this finding and issued a Notice of Violation (Notice) without a severity level and without a required response. The Notice was issued to document concern about the non-licensed operator's apparent misconduct and to emphasize management's

responsibility to assure that records are complete and accurate. The inspectors concluded that the licensee's corrective actions for this violation, documented in the previous inspection reports, were adequate. This item is closed.

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), Maintenance Planning System (MPS), 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 26835	MOV-HY-102A BARTS Testings
MWR 02684	MOV-SI-885A Limit Switch Adjustment
MWR 26934	Install Spare Heat Trace on Quench Spray System Test Line

The inspectors reviewed the paperwork for MWR 026934, observed the installation of terminations on the heat trace cable, and observed bench testing of the heat trace cable. The MWR instructions were to follow the instructions in the associated design change package (the design change was to install a second heat trace cable on the quench spray system test line). The design change package referenced a station electrical drawing for termination instructions; however, it was not clear on the referenced drawing what was expected with respect to termination at the end of the heat trace downstream of the power source. The electrical maintenance supervisor found appropriate termination instructions in the heat trace vendor technical manual. The electrical maintenance supervisor also had to resolve some other discrepancies with the work instructions concerning the required length of the heat trace cable and insulation resistance specifications. The inspectors concluded that the maintenance supervisor did a very good job of resolving the inadequacies in the work instructions. The inspectors discussed the inadequacies in the work instructions with the Director of Maintenance Planning, who explained that a thorough review of the maintenance planning process is in progress and should be complete around April. The results of the review should help to improve maintenance planning.

MPS 23481 Inspect Valve Internals on 2SWS-486

2SWS-486 is a vacuum break check valve on the discharge of service water pump 2SWS-P21A. The valve is inspected annually by the licensee as part of the preventive maintenance program. The procedure used by the licensee is 2CMP-75-WALWORTH CHECK-1M "Repair of Walworth Swing Check Valves Sizes 2 inches through 12 inches," which had been through the licensee's procedure upgrade program. The inspectors observed reassembly of the valve. The inspectors noted that the procedure was easy to follow and appeared technically correct. The maintenance technicians and the quality insurance inspector worked carefully, competently, and in accordance with the procedure to reassemble the valve.

3.1.1 Post-Maintenance Testing on 2MSS-18

In September of 1993, during the fourth Unit 2 refueling outage, the licensee disassembled and replaced the internal parts and the bonnet cover on 2MSS-18 (a steam supply check valve for the steam driven auxiliary feedwater pump). Since the valve was repaired, and is classified as American Society of Mechanical Engineers (ASME) Code Class 3 equipment, a VT-2 visual examination during a system pressure test was required to detect any post-maintenance leakage. That examination, however, is not required prior to returning the valve to service. On December 5, the valve was returned to service following a visual inspection by maintenance personnel rather than a formal VT-2 visual examination. The licensee does not specify VT-2 examinations as part of the post-maintenance test requirements, but instead tracks the requirement through a non-destructive examination request. A satisfactory VT-2 visual examination of this valve was performed on December 30, 1994. The licensee plans to improve timeliness of post-maintenance ASME required visual exams. The inspectors had no further questions in this area.

3.1.2 Target Rock Solenoid Operated Valve (SOV) Failures

In response to NUREG 1275, Volume 6, "Operating Experience Feedback Report - Solenoid Operated Valve Problems," and some problems they have recently experienced, the licensee has developed a task force to investigate this issue. The SOVs in question have a repetitive history involving failure to stroke, failure to meet stroke time acceptance criteria, or excessive seat leakage. The specific valves are the pilot-operated, soft seated SOVs in the Unit 1 head vent system, Unit 2 sample system (containment isolation valves), turbine driven AFW pump steam supply, and quench spray chemical injection pump discharge. The licensee attributed a recent failure of the Unit 2 turbine driven AFW pump steam supply valve to human error, inadequate procedures, and a lack of information regarding the valve (the valve had been incorrectly reassembled following maintenance). The inspectors also previously identified a problem of poor maintenance planning for the repair of a reactor vessel head vent isolation valve (see NRC Inspection Report 50-412/93-28).

The licensee maintains a material history trending program and root-cause analysis program, but only recently initiated action to address the current SOV concerns. The inspectors reviewed the maintenance history of the turbine driven AFW pump SOVs, sample system SOVs, and chemical injection pump discharge SOVs and noted that the failure history dates back to 1987. The maintenance department review of NUREG 1275 incorrectly concluded that the programs in place for monitoring/trending MWR and PM history in combination with the AirCet Program would implement all the recommendations in Subsection 9.2 of NUREG 1275." However, AirCet testing is only applicable to air operated valves and has no bearing on SOV maintenance. The licensee's maintenance, engineering, and licensing staff have identified a need for a site SOV program and have requested management action in this area. On January 1, 1994 a SOV component engineer was appointed within the maintenance organization.

The SOV task force review of this issue could have been more timely, however it is a good step toward improvement of reliability of the safety related systems in which these valves are installed.

3.1.3 Component Lubrication Program (URI 50-334/93-28-02) (Closed)

This unresolved item involved the failure to develop a lubrication schedule for the Unit 1 supplemental leak collection and release system (SLCRS) blower bearings. The licensee's root-cause analysis of the bearing degradation determined that the lack of lubrication was the cause.

The inspectors reviewed the Unit 1 and Unit 2 preventive maintenance greasing and lubrication programs to verify the appropriate safety related components (pumps, motors, blowers, limitorque actuators) were contained within the programs. The systems reviewed included reactor coolant, quench spray, charging, recirculation spray, low-head safety injection, and SLCRS. The Unit 1 sodium hydroxide chemical addition pump motors (QS-P-4A, 4B, 4C, 4D) were identified as not being in the lubrication program. The name plate data on the motors indicated "Chevron SRI #2" lubrication oil should be used. The safety significance of omitting these motors from the lubrication program is minor as the pumps are not normally in operation. Also, the pumps are in the licensee's in-service testing program and any degradation would be noted by vibration analysis. Licensee personnel also performed a comprehensive review of their lubrication program and additionally identified that the Unit 2 battery room exhaust fans (2HVZ-FN216A and B) were omitted. The licensee has since developed preventive maintenance lubrication tasks for these components. Overall, the inspectors found the licensee's lubrication program to be acceptable with only a few missing components. This unresolved item is closed.

3.1.4 Missing Unit 2 HHSI Pump Lube Oil System Brackets (Unresolved Item 50-412/93-09-02) (Closed)

In April 1993, six support brackets were found missing from the Unit 2 high head safety injection (HHSI) pump lube oil systems (see NRC Inspection Report 50-412/93-09). The reason for the missing brackets had not been determined and was identified as an unresolved item (50-412/93-09-02). The licensee's Independent Safety Evaluation Group (ISEG) attempted to determine why the brackets were missing. The exact cause was not determined. The inspectors reviewed the ISEG evaluation and the design change paperwork for the HHSI lube oil system modification, and interviewed maintenance personnel concerning the design change and routine lube oil cooler cleaning. The inspectors concluded that, regardless of the cause of the missing brackets, licensee personnel missed several opportunities to identify the deficient condition. In October 1992, the licensee did identify that one of the brackets was missing, but failed to take adequate corrective actions for the deficiency. This resulted in a Notice of Violation (50-412/93-09-03). In response to this violation, the licensee committed to additional maintenance and operations training to address the identification and reporting of degraded or nonconforming conditions. This commitment should be adequate to address the licensee's apparent weakness in the identification of the missing HHSI pump lube oil cooler brackets. This item is closed.

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), Beaver Valley Tests (BVTs), 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 1.24.9 Turbine Driven Auxiliary Feedwater Pump (FW-P-2) Operability Test
1MSP 6.14-1 P-457, Pressurizer Pressure Channel III Test
1BVT 8.3.1 Incore Movable Detector Flux Mapping
2OST-46.3 Six Month Hydrogen Recombiner 21A Test
2OST-36.17 RCP Bus Undervoltage Functional Test

3.3 Unit 1 Recirculation Spray Heat Exchanger Fouling

On January 7, 1994, Unit 1 river water pump 1A was aligned to put flow through the two 'A' train recirculation spray (RS) heat exchangers RS-E-1A and 1C using temporary operating procedure TOP 92-9. This was done so that an orifice flow element FL-RW-102A on the discharge of the RS heat exchangers could be used to perform the river water pump surveillance test because the ultrasonic flow detectors, located on a different flow path, were

proving unreliable. River water through the 'A' train RS heat exchangers was measured at 6100 gpm using FL-RW-102A. Technical Specification 3.6.2.2 requires that flow be restored to at least 8000 gpm within 72 hours. Attempts to meet the required flow were unsuccessful. On January 9, the unit was shutdown to clean the heat exchangers in order to restore full flow. As described in Section 5.3, the licensee declared an Unusual Event due to the required shutdown.

Both of the heat exchangers on the 'A' header were opened and cleaned. Loose debris consisting of rust scale and Asiatic clams (Corbicula) was removed. The tubes of the 1C heat exchanger appeared to the inspectors to be about 75 percent plugged with clams and the 1B tubes appeared to be about 10 percent plugged with clams. The 1A heat exchanger tubes were reported by the licensee to be about 50 percent plugged. The inspectors observed portions of the tube cleaning in all three heat exchangers and verified that the 1A and 1C heat exchangers were completely clean before closure. Post maintenance testing demonstrated operability with a river water flow rate of about 9700 gpm unthrottled and 8700 gpm throttled flow in each train.

Clogging of Unit 1 RS heat exchangers has been a recurring problem. Part of the problem is believed to be that the piping configuration creates a debris trap where the RS heat exchanger supply line taps off of the main river water header. The Unit 2 piping configuration does not present such a debris trap. Issues related to corrective actions for this recurring problem were the subject of a separate inspection as a result of this event. The results of that inspection are reported separately in NRC Inspection Report 334/412-94-03/03.

Technical Specifications require that river water flow through the RS heat exchangers be verified every 18 months. That flow verification was previously performed in May of 1993 following heat exchanger cleaning during the last refueling outage. Until corrective actions have been demonstrated to have resolved the problem of debris plugging of the RS heat exchangers, the licensee has plans to perform monthly testing of both RS trains to monitor debris buildup and verify that the heat exchangers would receive the required amount of river water flow. The first of these tests is scheduled for the week of February 14 for the 'A' header and for the week of February 21 for the 'B' header.

4.0 ENGINEERING (71707, 90712, 92700)

4.1 Review of Written Reports

The inspectors reviewed Licensee Event Report (LER) and other reports submitted to the NRC to verify that the details of the event 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 followup. The following LER was reviewed:

Unit 2:

93-10 "Reactor Coolant RTD Insulation Breakdown"

This issue was inspected in NRC Inspection Reports 50-412/93-23, 93-28, and Section 4.2 of this report. The inspectors have no further comments.

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

4.2 Resistance Temperature Detector (RTD) Degradation (VIO 50-412/93-28-02) (Closed)

This violation involved the failure of a Unit 2 reactor coolant system hot leg RTD due to inadequate thermal insulation. The lack of thermal insulation permitted convective heating of the RTD head to a temperature above its design temperature. The original installation specification per design change package (DCP) 1469 did not provide sufficient detail to ensure the RTD installation was consistent with the environmental qualification test report provided by the vendor. Immediate corrective actions have been completed by the licensee. This includes the replacement of all 12 Unit 2 reactor coolant system RTDs per DCP 2045. Sufficient thermal insulation was added around each RTD per the DCP installation specifications to protect against the effects of convective heating. The inspector reviewed the post modification testing calculations and found them to use standard, acceptable methods to determine expected qualified life. Contact integrating thermal monitors were installed at each RTD location in order to determine the temperature at each RTD over a full cycle of operation. The licensee plans on using this information to update the qualified life calculations at the end of this fuel cycle. The inspector considered these actions to correct this deficiency and preclude future RTD degradation to be sufficient. This violation is closed.

4.3 Corrective Actions for Cold Weather Problems at Unit 2

As discussed in Section 2.7 of this report, Unit 2 experienced several problems with frozen piping in January of 1994. All of the problems involved piping located in the refueling water stowage tank (RWST) enclosure, which does not have a roof and only has walls which surround the lower half of the RWST (and associated piping). Consequently, all piping which is important to safety is heat traced in this enclosure. The licensee has a history of cold weather problems with the heat trace circuits for components in the Unit 2 RWST enclosure, which date back to 1988. The licensee's past efforts to correct the problems have included increasing heat trace output capacity, adding redundant circuits, and insulating sensing lines from mounting brackets. The licensee also did extensive preventive maintenance on the heat trace circuits and associated thermal insulation during the summer of

1993. These efforts appeared reasonable; however, as demonstrated by recent events, the efforts have not been fully successful. The corrective actions for the problems experienced in January 1994 included modifications to increase the control temperature or control bands on the heat trace systems, installation of a temporary heated enclosure for some equipment in the RWST enclosure, increased monitoring of certain heat trace circuit parameters, periodic blow-down of the RWST level transmitters, repair of heat trace cable and replacement of insulation where necessary.

The inspectors concluded that the engineering evaluations associated with these recent modifications were adequate; however, the timeliness of one of the evaluations was poor. Jumpers were installed in the heat trace circuits for the safety injection system suction line, under the licensee's emergency work provisions, but this action was not followed-up by a 10 CFR 50.59 review until a week later (due to poor communications between the work groups). Additionally, the emergency work documentation associated with the installation of the jumpers in the heat trace circuits was weak. Station procedures require the shift supervisor to document on the MWR that there were no unreviewed safety questions and that the repair does not constitute a design change. The only documentation by the shift supervisors were signatures authorizing the work. The licensee is going to review emergency work provisions in a future operations training session and has initiated a problem report to establish and track corrective actions for the 10 CFR 50.59 timeliness issue.

The licensee has initiated a task team to assess the root cause of the recent events and establish long term corrective actions. The short term control and monitoring requirements put in place to ensure proper operation of the RWST level transmitters were comprehensive and conservative.

4.4 Wide Range Water Level (Unresolved Item 50-334/90-28-02; 50-412/90-28-02) (Closed)

The licensee has established detailed technical justification for Unit 1 wide range level monitor accuracy and range as documented in licensee's design analysis No. 8700-SP-1RC-01, "Setpoints for Reduced Inventory or Mid Loop Operation," Revision 1, May 15, 1993. The wide range monitor (LT-RC-482C) has an accuracy of 2 inches. The inspector interviewed licensee staff and reviewed the design analysis and found this accuracy to be acceptable for the system operation during mid loop configuration.

The water level alarms for Unit 1 and Unit 2 were provided and documented in procedures 1OM-10.4.4.AAH and 2OM-10-4.4.AAG, "RCS Mid-loop Level High." The inspector reviewed these procedures and found that these alarms provide sufficient information to effectively monitor RCS level during mid loop operation.

This item is closed.

5.0 PLANT SUPPORT (71707)

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. Except as described below, licensee personnel were observed to be properly implementing their radiological protection program.

5.1.1 Posting Discrepancy

During the inspector's tour of the Unit 1 primary auxiliary building, inconsistent radiological postings were noted for the 722 foot elevation valving cubicle. The doorway to the cubicle was posted as a "4A" (50-100 mr/hr). However, upon entry, the area was posted a "6B" (greater than 1,000 mr/hr). Additionally, the door lock was removed, but a posting on the door read "this barrier must remain locked at all times except for entry or exit." The inspector discussed this issue with the Unit 1 radiological controls director and was informed that the valving cubicle was down-posted to a "4A" the previous day. The health physics technician had, however, failed to remove the old postings. The highest actual radiation levels were 20 mr/hr at 1 foot. This posting discrepancy was promptly corrected.

5.1.2 Maintenance Worker Failed to Frisk After Leaving a Radiologically Controlled Area

During a routine site tour, a resident inspector observed an individual leave the Unit 2 refueling water storage tank (RWST) enclosure, through a temporary access point, and head away from the safeguards building. The safeguards building is designated as the required frisking location for individuals after they leave the RWST enclosure. The inspector checked the RWST radiological posting at the temporary access point and verified that the safeguards building was specified as the required frisking station. The inspector's observation was turned over to health physics personnel for resolution. Health physics personnel located the individual and determined that the failure to do a whole body frisk was not intentional. The individual, the individual's work area, and the area just outside the RWST enclosure were immediately surveyed and found free of contamination. The worker indicated that he did not see the posting on the door, which was open, and was not directly in front of the him when he left the area. The location of the radiological posting at the temporary access point was changed so that it was directly in the path of anyone leaving the RWST enclosure and the orders for the security guard at the RWST enclosure were changed to direct individuals leaving the area to go to the safeguards building and frisk.

The failure by an individual to perform a whole body frisk as required by a radiation work permit is a violation of technical specification procedural adherence requirements; however,

the violation is not being cited because of the low safety significance and the prompt, comprehensive corrective action taken (Section VII.B of the Enforcement Policy).

5.2 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.

5.3 Emergency Preparedness

At 7:40 p.m. on January 7, 1994, the licensee entered a 72-hour action statement when flow through the Unit 1 'A' train recirculation spray heat exchangers was determined to be less than required by technical specifications. At 11:00 a.m. on January 9, after attempts to increase flow were unsuccessful, the licensee determined that it would be necessary to shut down to clean the heat exchangers. The licensee declared an unusual event at 11:15 a.m. due to a plant shutdown required by technical specifications. The inspectors reviewed this event and determined that it was properly classified. All required notifications were properly completed including follow-up notifications which were completed twice per shift as required by the site emergency plan until event termination. The event was terminated at 1:30 p.m. on January 10 when the unit entered cold shutdown.

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. The inspectors noted a considerable amount of management attention to proper housekeeping and stowage. Training sessions were being developed to address previous deficiencies concerning the stowage of equipment in safety-related areas. Additionally, some areas of the plant, such as the Unit 2 safeguards building, have shown a significant improvement in general housekeeping.

5.5 Boron Analysis Procedural Compliance

During a routine inspection of the plant chemistry program, the inspectors observed a chemistry technician draw and analyze a reactor coolant system boron sample. On a subsequent review of the procedure, the inspectors noted that the technician had not performed the final steps of the procedure which require that the analyst add additional mannitol to the boron solution after the titration end-point (based on pH) is reached the first time. This requirement exists to confirm that the true end-point has been reached. If solution pH does not decrease after adding more mannitol, then the titration is over. If pH continues to decrease, the analyst must continue the titration. The analyst stated that he forgot the final steps because he had not performed the titration manually for a long time (the automatic titrator was out of service), and he did not review the procedure prior to performing the titration. The safety and technical significance of the technician's failure to follow the procedure was very low because: (1) his final result was consistent with previous results, indicating that the original amount of mannitol added to the solution was in excess of that required to react with all the boron; and (2) reactor coolant system boron concentration is not used to determine shutdown margin in Mode 1, but even if it was, any error in the analysis would have been conservative (i.e., would have given a lower than actual result). The inspectors were concerned, however, with the analyst's decision not to review a procedure which he had not performed in the recent past.

The inspectors' observations were discussed with the Director of Chemistry Operations. The licensee implemented the following corrective actions: (1) the analyst was counseled on his performance; (2) a change was initiated to the Beaver Valley Chemistry Manual to better define the licensee's expectations concerning the use of chemistry procedures (the revision explains that procedures should be reviewed or actively used for other than frequently performed analyses); and (3) this problem and the change to the Chemistry Manual will be discussed at training. The inspectors concluded that the corrective actions were appropriate. This failure to follow procedures is considered a violation of technical specification procedural adherence requirements; however, it is not being cited because of the low safety significance and the corrective actions taken by the licensee (Section VII.B of the Enforcement Policy).

5.6 Fire Protection Program Implementation Problems

On January 15, 1994, the licensee installed a propane space heater in the Unit 2 refueling water storage tank (RWST) enclosure as one of the actions to prevent ice formation in various fluid systems in the area. The individuals performing the fire protection review determined that a fire watch and notification of the Unit 2 Fire Protection Engineer were not required because the Hot Work/Fire Barrier Permit stated that compensatory actions for space heaters was "not applicable." This was an understandable determination based solely on the Hot Work/Fire Barrier Permit; however, Section G of Nuclear Power Division Administrative Procedure 3.5 requires that the Fire Protection Engineer be notified for space heaters placed in the RWST enclosure. On January 18, the Unit 2 Fire Protection Engineer

recognized that he had not been notified about the propane space heaters. He subsequently determined that a continuous fire watch was the appropriate compensatory action, and one was promptly established. The licensee has decided to change Nuclear Power Division Administrative Procedure 3.5 to more clearly define the requirements associated with temporary space heaters. The inspectors had no further questions in this area

On February 8, 1994, at 9:15 a.m., the shift supervisor identified that the Honeywell fire detection computer for Unit 1 had been inoperable for the previous 15 hours. This computer is associated with the fire detection instrumentation (heat and smoke detectors) for safety-related equipment. Further review of the computer printout determined that the system had been out of service since 5:28 p.m. on February 7. There are no audible or visible alarms to alert operators when the computer goes out of service. A computer printout in the back of the control room is all that is available to operators to indicate that the fire detection circuits are not in service. This printout is not, however, routinely checked by any operators during the conduct of their rounds. Upon identification of this deficiency, an hourly fire patrol was immediately established as required by administrative procedures. The Honeywell fire detection system was restored to operable status within 3 hours. The cause of the failure is currently under investigation. To more promptly identify malfunctions of the fire detection system, the plant operator is now required to log, twice per shift, that the Honeywell fire detection panel is operating. The inspectors had no further questions in this area.

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 February 14, 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
1/28/94	Heat Exchanger Fouling Corrective Actions	94-03/03	M. Buckley

6.3 NRC Staff Activities

Inspections were conducted on both normal and backshift hours: 20.2 hours of direct inspection were conducted on backshift; 28.1 hours were conducted on deep backshift. The times of backshift hours were adjusted weekly to assure randomness.

The inspectors gave the licensee a draft copy of the proposal cover sheet and letter announcing an Operational Safety Team Inspection (OSTI) at Beaver Valley. A copy of these documents is attached to this inspection report.

R. Barkanic, Pennsylvania Department of Environmental Resources, visited the site and the inspectors on February 3 and discussed inspection activities and the licensee's performance.