U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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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:	August 29 - October 9, 1995
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Reactor Projects Branch 7

Inspection Summary

This inspection report documents the safety inspections performed by resident inspectors in the areas of: plant operations; maintenance and surveillance; engineering; plant support; and safety assessment/quality verification. Additionally, inspections conducted by Region-based inspectors are documented in the areas of human performance and problem resolution, and environmental and meteorological monitoring. The results of these inspections are summarized in the executive summary.

EXECUTIVE SUMMARY

Beaver Valley Power Station
Report Nos. 50-334/95-16 & 50-412/95-16

Plant Operations

The finding of two mispositioned valves resulted in the licensee conducting extensive verifications of valve positions and other components. One significant finding, the overthrottling of service water valve 2SWS-MOV-105D, and several less significant mispositionings, have been identified. Thorough investigations have been performed for each finding and a conservative approach has thus far been taken for the overall issue. Valve verifications, root cause analyses, and corrective actions were continuing at the end of this inspection period. Concerns about performance in areas including independent verifications, work controls, and work practices are an **unresolved item**.

Maintenance

A review of the maintenance backlog was completed at both units. The number of open work requests has been decreasing due to recent licensee attention towards the backlog. No outstanding work requests were found which could pose a potential safety risk to the plant or raise operability concerns of safety related equipment. The licensee's maintenance history review program has also been effective in identifying repeat failures of equipment. A significant improvement has also been made in reducing the backlog of overdue maintenance history open items.

An error during motor operated valve testing from the past refueling outage resulted in an incorrect throttle position setting for a service water valve, 2SWS-MOV-105D. This, in turn, degraded the performance of a recirculation spray heat exchanger at Unit 2. Although this train of recirculation spray system would still have performed its safety function, concerns were identified regarding the motor operated valve testing. In addition to the error at the job site, the work package was incomplete, intervening adjustments to valve position indicator and computer point limit switches were not questioned, and final review failed to question the missing "as left" stroke data, which would have alerted personnel to the incorrect settings.

In summary, this event did not have a significant effect on the safety function of the recirculation spray system, although concerns were identified involving personnel performance during MOVATS testing, MOVATS data review, and operations/maintenance interface of test results. In addition to promptly correcting the misthrottled position of 2SWS-MOV-105D, the licensee has initiated comprehensive corrective actions to prevent recurrence. The failure to satisfy technical specification requirements for assuring that four separate and independent recirculation spray heat exchangers were operable is a violation. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

Engineering

The implementation of a design change to correct a single failure vulnerability in the switchyard relay protection scheme was well implemented.

(EXECUTIVE SUMMARY CONTINUED)

Very good controls over the switchyard activities were evident, as licensee management was actively involved in ensuring prerequisites were satisfied and expectations were understood.

Plant Support

Actions to address the finding of tritium in the secondary side of both units were initially weak because station chemistry personnel did not initially inform the operations department or effluents controls personnel of the finding. Also, no attempt was initially made to quantify the primary to secondary leak rate at Unit 2. Isotopic analysis subsequently demonstrated that there is no quantifiable primary to secondary leakage at either unit.

The licensee maintained excellent radiological environmental monitoring and meteorological monitoring programs. The management of these programs has remained stable for a number of years, with well qualified and experienced personnel performing the required functions according to well-written procedures. The radiological environmental monitoring program incorporates an excellent quality control program for analytical measurements.

The licensee thoroughly planned, installed, and implemented a biometrics (hand geometry) access control system. Security has also been actively involved in evaluating all component mispositioning events. No tampering has been identified.

Delays in supplying parts for maintenance were attributed to weaknesses in procurement and inventory tracking. The licensee is in the process of reassessing the procurement system and processes to develop the necessary corrective actions.

Safety Assessment and Quality Verification

A well formulated problem reporting program has been established to identify and resolve low threshold incidents. Licensee management is aware of program limitations and is evaluating measures to refine problem reporting processes. The licensee's root cause analysis system provided a balanced method for identification of both equipment and human performance weaknesses which should provide adequate means of identifying causes of problems and associated corrective actions. Administrative procedures and implementing guidance provide adequate guidance for the use of the system. The licensee has implemented a good human performance improvement program. The plan includes a strong self-check and attention to detail program. Senior management involvement and commitment to these programs is continuing to heighten staff awareness of performance and work practice expectations.

The licensee's program for checking all 10 CFR 50 Appendix B supplied fasteners is a good initiative and identified an instance of defective safety-related hex head screws. Licensee actions to identify, pursue, and report this issue are noteworthy.

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DETAILS

1.0 MAJOR FACILITY ACTIVITIES

Both units operated at full power throughout this inspection period without any significant operational events.

2.0 PLANT OPERATIONS (71707)

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: quench spray chemical addition, diesel generator fuel oil, auxiliary feedwater, and quench 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 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 TSs and implementation of appropriate action statements for equipment out of service were inspected. Logs and records were reviewed to determine if entries were accurate and properly 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 Component Mispositionings

On September 20, 1995, the inspectors observed that level indicating switch LIS 205A on the Unit 2 emergency diesel generator 2-1 fuel oil day tank was reading several inches lower than two other level indicators, LIS 203A and LIS 204A, on the same tank. The licensee investigated and found that this was because the instrument isolation valve for LIS 205A was mispositioned closed. LIS 205A provides the plant computer and local annunciator with a fuel oil day tank level signal. Operators also take their diesel 2-1 fuel oil day tank level readings from this indicator. This instrument does not have any control function for the diesel fuel oil transfer system. LIS 203A and LIS 204A provide the low level and high level signals to start and stop the diesel 2-1 fuel oil transfer pumps. The licensee thoroughly investigated this event. The licensee's review team concluded that the instrument isolation valve was most likely left closed by a chemist on September 14 when the valve was closed to take a fuel oil sample via the LIS 205A instrument line, although an independent verification was performed to verify that the sample valves were left in the proper position. The level signal recorded by the plant computer supported the conclusion that the instrument was isolated since the September 14 sampling and there were weaknesses in the verification techniques used by the independent verifier. The chemistry department manager has directed the staff on correct verification performance and increased supervisory oversight of verifications.

On September 21, 1995, an instrument technician reported that he found valve QS-173 mispositioned open when he began the calibration of pressure indicator PI-QS-400B, the discharge pressure indicator for Unit 1 chemical addition pumps QS-P-4B and 4D. Valve QS-173 is the isolation valve for PI-QS-400B and is located in the Unit 1 chemical addition building. This valve is normally shut but is opened for surveillance testing of the chemical addition pumps. Valve QS-173 was manipulated during chemical addition pump surveillance testing on September 19 and it was independently verified by operations to be in the correct position (shut) at the conclusion of the test. The licensee thoroughly reviewed this event and concluded that either the technician was wrong about the as-found position of valve QS-173 or the valve had not been restored to normal station alignment following surveillance testing on September 19, 1995.

The licensee took several actions as a result of these events. The licensee performed verification checklists of safeguards equipment at both units and found no mispositioned components. Beginning September 21, all operations and instrumentation valves in the Unit 1 chemical addition building and in the Unit 2 emergency diesel generator building were verified. All valves were found to be in the correct position except for two instrument drain valves on the diesel 2-2 fuel oil strainer pressure differential gauge DIS-201C which were found open when they should have been shut. These drain valves are not subject to independent verification but good work practices and any maintenance activities performed on instrument DIS-201C should have left them shut. No cause could be determined for the as-found position of these instrument drain valves.

Beginning September 22 the licensee took the following additional actions: Routine performance of the safeguards checklists were initiated. A six to eight week effort was begun to verify valve checklists for accessible safety related and power production valves. A review team, chaired by the General Manager of Operations, was formed to review these events. Several operators were selected to be designated independent verifiers to perform required independent verifications. Supervision was also increased when returning equipment to normal station alignment following work activities.

Several additional mispositionings were identified after these actions were taken. Only one of these findings had potential safety significance. That finding was the overthrottling of valve 2SWS-MOV-105D due to maintenance errors during the previous refueling outage and is discussed separately in Section 3.1.3 of this report. All findings received a thorough review by the review team and site security. None of the events have been attributed to tampering.

System walkdowns, root cause analyses, and development of further corrective actions were continuing at the end of this inspection period. The inspectors concluded that thus far the licensee has taken thorough actions to investigate and correct each finding. These events do however raise concerns about the performance of independent verifications, work controls, and work practices. These issues will continue to be followed (**unresolved item 334/412-95-80-04 updated**).

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) listed below were observed and reviewed. Unless otherwise indicated, the activities observed and reviewed were properly conducted.

MWR 045967 Troubleshoot Emergency Switchgear Ventilation Damper

MWR 046113 Calibrate Steam Generator Level Transmitter 2FWS-LT-475

MWR 046547 Loss of Bus 3 Inverter Output

MWR 045454 Calibrate Main Steam Pressure Transmitter 2MSS-PT-464 (see Section 5.5)

MWR 046208 Repair Emergency Diesel Generator 2-1 Jacket Water Leak (see Section 5.5)

MWR 046298 Replace Motor Operated Potentiometer for Emergency Diesel Generator 2-1 (see Section 3.1.2)

3.1.1 Maintenance Backlog Review

The inspectors performed a review of all outstanding Unit 1 and 2 MWRs as of August 3, 1995. This totaled 4034 items (2098 outage and 1936 non-outage MWRs). The purpose of this review was to determine if the backlog of safety-related maintenance activities is being appropriately managed by the licensee and if any uncorrected plant deficiencies existed which could potentially impact plant safety. The inspectors reviewed in detail all safety-related MWRs and selected non-safety related MWRs. Approximately 18% (348 MWRs) of the non-outage backlog for both units included safety-related maintenance. Approximately 57% (1202 MWRs) of the outage backlog for both units included safety-related maintenance. The outage MWRs were also reviewed by the inspectors to ensure that these items were properly prioritized and categorized to determine if any of them should have been worked during the last refueling outage. Non-outage maintenance items were being properly assessed and scheduled for work per the licensee's 12-week maintenance schedule. The maintenance department was also active in re-evaluating outage MWRs for work during non-outage conditions. Recent licensee attention towards the maintenance backlog has resulted in a reduction in open non-outage MWRs. The non-outage backlog has been reduced from a peak of 2573 MWRs in April to 1936 MWRs in October. The licensee has recently completed a review of the maintenance backlog of items greater than 1 year old. No deficiencies were identified by the licensee which would pose equipment operability concerns. Overall, the inspectors found that there were no open MWRs which posed a safety risk to the plant or raised operability concerns of safety-related equipment.

The inspectors did have the following additional observations:

The administration of the backlog, especially those involving I&C maintenance, was poor. Specifically, dozens of MWRs from the Unit 2 refueling outage (which ended in May) involving safety related maintenance were designated as still being "active." This gave the appearance that operability concerns existed on technical specification equipment. In fact, the actual maintenance and operability testing was complete. This would include, for example: bad relay cards in secondary process racks; bad controller cards for pressurizer level protection; and reactor coolant delta-temperature protection loop erratic amplifier cards. Numerous MWRs were indicated as being active or in planning, when in fact they were obsolete and no longer applicable due to various circumstances. For example, open MWRs existed for control room annunciators which had been retested satisfactorily by Operations. The poor administration of the backlog creates difficulty in the ability to properly assess open MWRs for status, prioritization and safety significance. This situation has subsequently been corrected by the licensee.

No mechanism was in place to alert operators to computer points with suspect calibration. These points have the potential to provide operators with misleading information which operators would have no reason to question. For example, the 'B' service water pump motor upper bearing temperature computer point is out of tolerance. The licensee has subsequently removed these suspect computer points from scan while the MWRs are active.

Examples of weaknesses were identified in the characterization, categorization and timeliness of disposition of some items: (1) Three MWRs on balance of plant equipment identified unevaluated plant modifications. (2) One MWR indicated that a fire system pressure gage used in the weekly motor driven fire pump surveillance test could not be calibrated. This was not identified to the plant operators, who continued to use the gage. (3) One MWR identified a safety related valve with insufficient thread engagement. After six months, the deficiency had not been repaired or evaluated. (4) Three MWRs identified temporary fire seals that were not logged in the temporary fire seal log. (5) The Fire Protection System Engineer was not aware of several fire protection system deficiencies because of the way the equipment was categorized. The associated equipment was listed under system 75 (miscellaneous) and was not annotated as fire protection related. None of the identified issues appeared to represent a plant safety problem or an unreviewed safety question. The licensee is evaluating these observations for appropriate resolution.

3.1.2 Maintenance History Review

The inspectors performed a review of the licensee's maintenance history review (MHR) program to ensure that repetitive failures or other adverse trends which may indicate ineffective or inadequate maintenance are identified. On alternating calendar quarters, a problem equipment report is generated for each unit. The criteria for listing equipment in the report is any component model numbers that have four or more failures within the previous 15 months. A new criteria was recently added to include any equipment mark number which experienced three or more failures during a 12-month time frame. A multi-disciplined working group is tasked with determining the underlying reasons for each failure and providing solutions that would prevent recurrence. The MHR open items also receive senior management attention via the annual steering committee. The inspector reviewed the Unit 2 Problem Equipment Report, dated August 21, 1995, and noted that the licensee has been effective in identifying repeat failures of components. For example, action plans are under development to address air regulator diaphragm failures of Masoneilan valve operators and failures of Borg Warner hydraulic valve operators. NRC Inspection Report 94-81 previously identified problems with timely status information concerning proposed corrective actions and a large backlog of overdue items in the MHR backlog. One of the licensee's corrective actions was to add open items and their due dates to the maintenance commitment tracking system to raise their visibility. The inspector determined that this action was effective as evidenced by the significant reduction in the MHR backlog. The total number of MHR items has been reduced from 100 (December 1994) to 47 (September 1995) open items with only five items overdue (vice 41).

The inspectors noted that the quality of the MHR data base is highly dependant on the field maintenance personnel correctly identifying if a component "failure" occurred. Non-failures are not captured by the MHR program. This concern was previously expressed in NRC Inspection Report 94-24/25 involving the emergency switchgear ventilation fans. Multiple MWRs written to address the need for equipment adjustments have not necessarily resulted in "failure" designations although there may be a problem of ineffective maintenance. For example, the inspector reviewed the maintenance history associated with the diesel generator motor operated potentiometer (MOP). Since July 1993, maintenance has been performed on the MOP five times (MWRs: 033114, 019133, 031265, 043476, and 046298) to correct load swings or voltage adjust problems. Equipment failure was only coded on one MWR; thus, the four other MWRs would not be included in the MHR scope. To address the broader issue, the licensee has recently implemented a monitoring and trending program to comply with the maintenance rule. Completed MWRs are to be reviewed by the system engineer to determine if a maintenance preventable failure occurred. The licensee's program requires that a historical review of MWR history should be performed if the degradation is classified as "unknown" and a determination made if additional action or future trending is necessary. The effectiveness of this program could not be assessed due to its recent implementation. Also, the duties and responsibilities of system engineers is currently under re-evaluation by the licensee. The licensee is currently attempting to determine if any actions are required to prevent recurrence of this degradation for the MOP.

3.1.3 Misthrottled Position of 2SWS-MOV-105D

On October 3, 1995, it was observed that the valve stem position for the 2SWS-MOV-105D was different than that for 2SWS-MOV-105A, B, and C. These valves are the service water discharge isolation valves for their respective recirculation spray heat exchangers. These motor operated valves (MOVs) do not receive any engineered safeguards signals and are normally throttled open. Further investigation confirmed that the discharge isolation for the 'D' heat exchanger was excessively throttled. This valve was throttled only 2 1/8 inches open, but should have been throttled 5 1/16 inches open. After this was identified, the 'D' recirculation spray heat exchanger was declared inoperable per Technical Specification 3.6.2.2. Valve 2SWS-MOV-105D was adjusted to the correct position, the limit switches were re-adjusted to correspond with the proper throttled position, the valve was successfully stroke tested, and the 'D' recirculation spray heat exchanger was declared operable at 1440 on October 4.

The throttled position for these service water MOVs was initially established per a full flow design basis service water test (2OST 30.13B) on April 24, 1995. Motor operated valve testing (MOVATS) was subsequently conducted on

April 25 to set the open limit switch for 2SWS-MOV-105D to correspond with the established throttled position. The inspectors and licensee personnel reviewed the outage work documentation (MWR 031246) to determine the cause for the discrepancy between the "as found" throttled position and the pre-established throttled position. The work package documents a proper stroke time of about 19 seconds (corresponding to 5 1/16 inches open) after adjustment of the open limit. After removal of the MOVATS test equipment (torque/thrust cell-TTC), the maintenance procedure directs that an "as left" valve stroke is performed to ensure all contacts are properly changing state. Review of this data revealed an 8.55 second stroke time (corresponding to 2 1/8 inches open). Thus, an error was introduced during the process of removing the test equipment. The licensee was able to determine that the electricians failed to ensure the valve was on its backseat (*i.e.*, the reference point) prior to the removal of the TTC. This in turn introduced a 3-inch error for the open limit switch. After removal of the TTC, the electricians had to readjust the limit switches for the valve computer point and closed position indication. This re-adjustment should have alerted electricians that the limits had changed.

The inspectors and licensee personnel also noted that other opportunities existed in which this error could have been readily identified. The final, "as left" valve stroke information of 8.55 seconds was not recorded as part of the work package, thus this information was not reviewed for acceptability. The "as left" information was recorded on the computer diskette but not transferred to the work package despite instructions to do so. And, the interface between the Operations post maintenance stroke testing and the test results from the MOVATS test was found to be lacking. Operations recorded the stroke time as being 8.5 seconds after three successive strokes, but this data was not compared to the documented MOVATS data of 19 seconds for acceptability. Also, based on valve stem position observations, the inspector previously questioned in July 1995 if the licensee was confident that valve 2SWS-MOV-105D was properly throttled. The licensee believed that successful inservice testing and the open position indication of the main control panel confirmed correct valve position. Although system engineering did not pursue the question deeply enough to identify the mispositioning, they did consider and rule out the potential for repositioning of this valve by tampering due to the difficultly of changing the position of this valve without bringing in an alarm or a dual position indication light. To ensure that this same type of error did not occur with other MOVs, the licensee completed a review of MOVATS test data and actual stroke times as recorded in the in-service testing program. The inspectors also independently reviewed the MOVATs results on computer diskettes for final "as left" conditions for comparison to current stroke time information. Included in this review were the throttled river water MOVs for the Unit 1 recirculation spray heat exchangers. No other discrepancies were found. The licensee is currently pursuing a formal root cause and corrective actions for this event.

The safety significance of the misthrottling of this valve, in conjunction with the previously reported mispositioning of 2SWS-82 (see NRC Inspection Report 50-412/95-80) was evaluated by the engineering department and reviewed by the inspectors. Service water flow through the 'B' train recirculation spray system was calculated to be 6,221 gpm and 3,562 gpm for the 'B' and 'D' heat exchangers respectively during design basis accident conditions (DBA). This results in a total flow of 9,783 gpm, which is less than the technical specification minimum of 11,000 gpm. Further analysis was done to determine how this affected the heat transfer capability of the heat exchangers. Calculations were performed using both the design basis limit of 89°F river water temperature and the actual peak temperature of 86°F, during the period the valve was mispositioned. This calculation was performed to only include the 'B' train, as the 'A' train was assumed to be out of service as part of the initial conditions. The acceptance criteria for the containment depressurization analysis requires that following the DBA, containment be returned to subatmospheric conditions within 3,600 seconds and be maintained subatmospheric following the depletion of the refueling water storage tank. This condition was satisfied, in the above analysis, for actual and design basis conditions. For the 89°F condition, depressurization time was 3,470 seconds and a subatmospheric peak of -0.06 psig was calculated with additional margin available. Thus the 'B' train of recirculation spray system would have performed its intended safety function.

Notwithstanding the above conclusions that this event did not have a significant effect on the safety function of the recirculation spray system, concerns were identified involving personnel performance during MOVATS testing, MOVATS data review, and operations/maintenance interface of test results. In addition to promptly correcting the misthrottled position of 2SWS-MOV-105D, the licensee has initiated comprehensive corrective actions to prevent recurrence. The failure to satisfy technical specification requirements for assuring that four separate and independent recirculation spray heat exchangers were operable is a violation. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

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 procedure (MSP) listed below were observed and reviewed. Unless otherwise indicated, the activities observed and reviewed were properly conducted without any notable deficiencies.

2OST-1.12.B	Safeguards Protection System Train 'B' SIS Go test
2OST 36.2	Emergency Diesel Generator Monthly Test

The inspectors noted proper second verifications by the "designated second verifier" during system restoration following the surveillance. Additional independent oversight was provided by the assistant nuclear shift supervisor.

2MSP 4.03	Instrument Transmitter Line-up Verifications

Proper independent verifications were observed by the inspectors during the line-ups completed by I&C technicians.

4.0 ENGINEERING (37551, 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:

LER 95-005	Missed Surveillance-Quadrant Power Tilt Ratio Calculation not Performed
LER 95-006	Reactor Trip due to Main Generator Loss of Field

The above events were reviewed in NRC inspection report 95-13. The inspectors had no further comments and these LERS are considered closed.

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. These event reports are closed based on in-office review of the event report and onsite inspections.

4.2 Switchyard Protection Relay Design Change

Licensee evaluation of NRC Information Notice 91-81, "Switchyard Problems That Contribute to Loss of Offsite Power," resulted in the identification that Beaver Valley may have similar vulnerabilities. Specifically, it was identified that the stuck breaker failure unit (SBFU) relays for switchyard line and bus backup protection are all powered from the same switchyard DC control system. This design is subject to a single failure. Design change 2029 was implemented during this inspection period to correct this vulnerability. The inspectors reviewed the technical adequacy of the design change and observed the switchyard activities which implemented this change.

The scope of the design change was to transfer the control power source for the line and bus backup timer relays associated with the Number 2 138 kV Bus and the Number 4 345 kV Bus from switchyard battery 'B' to switchyard battery 'A'. The identification of this design vulnerability did not compromise the design basis for the switchyard. Licensee design basis documentation accounts for two independent primary and secondary protection relay schemes for offsite power. The SBFUs are part of a tertiary level of protection which is not part of design basis. The design change documentation was thorough and the instructions for implementation of the modification contained appropriate precautions and prerequisites, with the exception of ensuring that transferring the Unit 2 house loads from offsite power to on-site power via the unit station system transformers was documented as a prerequisite in the work instructions. Due to the potential impact on the offsite network if an error were to occur, this activity was designated as an "Infrequently Performed Test or Evolution." The Unit 1 Operations Manager was designated as the responsible test manager. Precautions and expectations were well communicated between offsite personnel and station management during the pre-job briefing. The actual field activities by substation personnel were completed in a cautious manner with good self checking applications. Overall, good control and coordination between substation and site personnel continue to be evident during the control of switchyard maintenance.

5.0 PLANT SUPPORT (71750, 71707, 84750)

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 the radiological protection program.

5.1.1 High Secondary Tritium Activity

On June 6, 1995, chemistry personnel detected low levels of tritium in the Unit 1 steam generators (about 1.6 E-5 μCi/ml). On June 7, a Unit 1 steam generator resin column analysis for isotopes was performed in an attempt to identify nuclides other than tritium. This methodology is capable of quantifying a leak rate, from the reactor coolant system to a steam generator, on the order of magnitude of one-tenth of a gallon per day. The resin column analysis did not identify any other nuclides, and thus did not result in a quantifiable leak rate. On August 7, chemistry personnel identified tritium in the Unit 2 steam generators. The tritium levels at Unit 2 were near the minimum detectable activity levels (about 8 E-6 μCi/ml). Because Unit 2 did not have a history of tritium problems, no attempt was made to quantify the primary to secondary leak rate with the enhanced resin column sampling procedure until questioned by the inspectors. Subsequent resin column sampling on August 31 did not identify any other nuclides, and thus did not result in a quantifiable leak rate.

Because the Unit 1 and 2 steam generator leak rates were not quantified, the Chemistry Department did not immediately inform effluent controls personnel or operations personnel of the tritium levels at either unit. Consequently, no actions were initially taken to calculate tritium environmental release rates and dose consequences. On August 15, 1995, effluent controls personnel became aware of the tritium activity when it was mentioned during a Health Physics and Chemistry subcommittee meeting of the Offsite Review Committee. Release rates and dose calculations were then evaluated for the steam generator tritium levels. The calculations conservatively assumed the reactor coolant system tritium activity was discharged to the environment at a leak rate of 0.1 gallons per day. This rate of release had no impact on offsite dose totals, but, nonetheless, must be considered.

The Chemistry Department plans to revise their steam generator sample procedures to require resin column analysis following initial detection of tritium activity in a steam generator. The procedure will also be changed to require prompt notification of effluent controls and operations personnel. The inspectors concluded that these changes were appropriate, and emphasized the importance of prompt communications regarding all plant anomalies and problems.

5.1.2 Radiological Environmental Monitoring Program

5.1.2.1 Management Controls

Program Changes and Responsibility

The inspector reviewed the organization responsible for implementation of the Radiological Environmental Monitoring Program (REMP) and discussed with the licensee any changes since the inspection conducted in March 1994. Since the previous inspection, there have been no changes in either the organization or the oversight of the REMP.

Review of Annual REMP Report

The inspector reviewed the Annual Radiological Environmental Monitoring Program Report for 1994. This report provided a comprehensive summary of the analytical results of the REMP around the Beaver Valley Station and met the Technical Specifications (TS) reporting requirements. The report also included the results of the land use census and the EPA cross-check program. No obvious omissions or anomalous data were identified. The reviewed results indicated that all samples were collected and analyzed as required and that the lower limits of detection specified in the TS were met. The inspector also reviewed the selected analytical REMP data records for 1995 to date during this inspection. The reports were complete and the reviewed data indicated no adverse radiological impact on public health or the environment.

Quality Assurance Audits

The inspector reviewed the following audit reports as part of the evaluation of the implementation of TS requirements:

BV-C-94-10, "Quality Services Audit of Site Environmental Monitoring Programs", conducted August 8 - September 29, 1994.

The Nuclear Procurement Issues Committee (NUPIC) audit of Teledyne Brown Engineering (TBE) Environmental Services, was led by Wolf Creek Nuclear Operating Corporation (Audit Number T105-K011), August 1 - 5, 1994. (Responses to NUPIC audits have been provided by TBE, and accepted by the auditors. A subsequent surveillance was conducted on April 19-20, 1995, to assess the implementation of the corrective action to the

Reports of Noncompliance. Results indicated that effective corrective actions have been implemented.)

The above audits were performed by qualified personnel and were of sufficient technical depth to properly assess the implementation of the programs. The inspector also reviewed the associated surveillance reports and noted that the surveillances were of sufficient technical depth to assess particular aspects of the REMP and MMP.

5.1.2.2 Implementation of the REMP

Members of Safety and Environmental Services have responsibility for implementing the REMP. A representative of the licensee's contractor, Teledyne Brown Engineering Environmental Services (formerly Teledyne Isotopes) collected environmental samples and maintained the sampling equipment. The environmental samples were sent to the contractor laboratory where the analyses were performed and the program summary, which is documented in the annual REMP report, was prepared.

The inspector noted that the individual responsible for sample collection had excellent knowledge not only of the requirements for sample collection, but also of the technical principles necessary for properly implementing these collections and for preparation of samples for shipment to the analytical laboratory.

REMP Procedures

The inspector reviewed the Environmental Procedure Manual (EPM) as part of the evaluation of the implementation of the REMP. The EPM included a description of the program, sample collection procedures, and data submittal and review. The EPM also contained the contractor laboratory's procedures for sample analysis. The inspector noted that the procedures were concise and provided the required guidance for implementing an effective REMP.

Based on the above review of the manual and discussions with the licensee representatives, the inspector determined that the licensee had a very good procedure manual with which to implement the REMP.

Direct Observations

The inspector examined selected environmental sampling stations to determine whether samples were being obtained from the locations designated in the Offsite Dose Calculation Manual (ODCM) and whether the air samplers were operable, calibrated, and maintained. These stations included air samplers for particulate and airborne iodines, automatic composite water samplers, milk, vegetation, and a number of thermoluminescent dosimetry (TLD) stations for direct ambient radiation measurements. All the air sampling equipment was operational, TLDs were placed at their designated locations, and the water compositors were operating and taking samples. Milk and vegetation samples were available and collected from the locations specified in the ODCM. The inspector witnessed the contractor collect water samples. The inspector noted that in addition to the collection of air particulate/air iodine and water samples, the licensee conducted weekly inspections of the air samplers and water compositors approximately midway between the sample collection dates. This activity, which is considered a program strength, provides an opportunity to replace, or to return to service any equipment that has failed, so that the amount of down time is kept to a minimum.

Based on independent observations and interviews with the contractor, the inspector determined that sample collection was performed correctly according to the appropriate procedures.

Environmental Dosimetry Program Comparison

The results of the NRC Thermoluminescent Dosimeter (TLD) Direct Radiation Monitoring Network are published quarterly in NUREG-0837. This network provides continuous measurements of the ambient radiation levels around 72 nuclear power plant sites throughout the United States. Each site is monitored by approximately 30 to 50 TLD stations in two concentric rings extending to about five miles from the nuclear power plant.

One purpose of this network is to provide a means of comparing the results of licensee direct radiation monitoring programs conducted around individual nuclear power plants with that of the nationwide NRC program. Therefore, several NRC TLDs are collocated with selected licensee TLD stations.

The inspector noted that the licensee tracks, trends, and reviews the TLD results, including those of the NRC-collocated TLDs. The inspector discussed and reviewed the results with the licensee and noted that the licensee's quarterly results during 1994 and 1995 to date were generally sightly lower than those of the NRC. This difference may be due to different dosimeter types, different transit doses, differences in time of field exposure, and specific TLD location variations. In view of the above uncertainties and variabilities, the results of the two sets of TLDs compare favorably.

Quality Assurance and Quality Control for Analytical Measurements

The inspector reviewed the licensee's programs for quality assurance (QA) and quality control (QC) to determine whether the licensee had adequate control with respect to sampling, analyzing, and evaluating data for the implementation of the REMP.

The licensee had a very comprehensive QA/QC program which included the contractor laboratory, the quality control laboratory, and an independent laboratory. The quality control program for the analysis of environmental samples included blind duplicates, splits, and spiked samples. The results were generally in agreement with the known values, with few exceptions. Reasons for the disagreements were investigated and resolved. The results were documented in the annual report.

Each laboratory maintains its own QC program including participation in the EPA cross-check program. The inspector reviewed the results and noted that they were within the EPA acceptance criteria. The results were documented in the annual report.

The inspector noted that the licensee continued to maintain an excellent QA program to ensure that the routine and non-routine REMP sample results were thoroughly reviewed by the senior environmental services specialist. Any results that appeared suspect were recounted and reviewed.

Based on the above reviews and discussions with the licensee, the inspector determined that the licensee had excellent QA and QC programs.

5.1.2.3 Meteorological Monitoring Program (MMP)

The inspector reviewed the licensee's MMP to determine whether the instrumentation and equipment were operable, calibrated, and maintained. The meteorological tower is equipped with redundant wind speed, wind direction, and temperature sensors at the 35, 150, and 500-foot elevations. Calibrations were performed quarterly, which is more frequent than the semi-annual TS requirement. The calibrations were performed by the vendor using the licensee's procedures. The inspector reviewed the calibration results for the preceding four quarters (December 1994 through September 1995) and noted that the calibrations were performed as scheduled and the results were within the licensee's defined acceptance criteria.

The inspector verified the licensee's capability to obtain real-time meteorological conditions, such as the wind speed, wind direction, and delta temperature values from the primary tower equipment. The inspector compared the real-time data from the strip charts at the weather station to the digital 15-minute averages displayed in the control room, Unit 1. The results were in agreement, taking into account the variance in the data. The inspector noted that all the sensors on the tower were operating at the time of the inspection.

Based on the above inspector observations, record review and discussions with the licensee representatives, the inspector determined that the licensee continued to implement an effective MMP.

5.2 Security

The security department actively participated in the root case task force for the mispositioning events discussed in Section 2.2, and they independently evaluated the events. No tampering was identified for any of the events.

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 their packages were properly searched and access control was in accordance with approved licensee procedures; security access controls to vital areas were maintained and persons in vital areas were authorized; security posts were properly staffed and equipped, security personnel were alert and knowledgeable regarding position requirements; written procedures were available; and lighting was sufficient.

The inspectors also observed implementation of a biometrics (hand geometry) access control system. The inspectors observed that a second row of exit turnstiles was installed for this system consistent with the security plan. News letters and other station announcements kept station personnel well informed of the access control system changes prior to implementation. Each badged individual received thorough individual training when enrolled in the biometrics system. Station security activated the biometrics access control system 1 week before the system was implemented which allowed security and all station personnel to gain experience with the new system. No problems occurred when the biometrics system was implemented on September 20, 1995. Visitor escort instructions were later improved based on experience gained during the first week under the new system. Overall, the inspectors concluded that the licensee thoroughly planned, installed, and implemented the new biometrics access control system.

5.3 Chemistry

The sampling and analysis of a shipment of Number 2 diesel fuel oil for the Unit 2 emergency diesel generator was inspected. The inspector observed that the fuel oil was sampled in accordance with ASTM D4057-81 as required by technical specifications. The inspector observed that testing of the oil was performed in accordance with technical specifications and the licensee's Chemistry Manual. The inspectors also verified that all of the fuel oil test results met the requirements of technical specifications prior to adding the fuel oil to the storage tank.

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 Procurement Support of Maintenance

On September 18, the licensee identified a minor jacket water leak on the 2-1 emergency diesel generator from the accumulation of water in the rocker arm lube oil reservoir. The source of the leak was identified as an exhaust valve O-ring for the number 1 cylinder. The inspectors observed this maintenance and noted that the pre-job planning could have been better, as no replacement O-rings were initially available at the job site after the diesel had already been removed from service. The inspectors were informed that the stock computer data base indicated that two sets of O-rings were on hand in the store room, but none were actually available when the mechanics attempted to retrieve the parts. Mechanics were, however, able to locate quality control acceptable O-rings from their own supply of extra parts; thus, the job was not significantly delayed. The inspectors discussed this issue with the Procurement Manager, who later determined that the O-rings were previously moved to another location within the same drawer by procurement personnel, but the identifying bin tag was not moved. In addition, the O-rings were not aggressively searched for by Procurement personnel when the material was requested.

On September 16, the main steam pressure transmitter (2MSS-PT-464) for the condenser steam dumps failed. Per Emergency Operating Procedure ES-0.1 "Reactor Trip Response," Step 2, the steam dumps are to be transferred to the "steam pressure" mode in order to automatically maintain steam generator pressure at the designated no load value (1005 psig). This transmitter failure had, however, disabled the automatic operation of the steam dumps in the "steam pressure" mode. Manual control of the steam dumps would still be available; however, this would be considered a significant operator work around during post trip recovery. The Instrumentation and Controls Director was questioned as to when these repairs would occur; however, the inspectors were informed that a new transmitter would not be available from the vendor until January 1996. Purchase records indicated that the order point for this model transmitter is when zero are remaining in stock, and the average lead time for delivery is 19 weeks. The inspectors reviewed the failure history of this transmitter and noted that this was the third failure in the past year (MWR 033041-September 26, 1994 and MWR 044183-August 7, 1995). Accordingly, the inspectors discussed with the Procurement Manager the logic of the current stocking level for this transmitter and efforts to procure a replacement transmitter given the multiple failures that have occurred, the important to safety role of the transmitter, and long lead time. Subsequently, on October 2, several transmitters were located on site by procurement during a continuing review of excess parts not in the material management stock system. A new transmitter has been installed, and a root cause analysis is being performed by the vendor to identify the possible cause of the repeat failures.

Given the examples discussed above, and other procurement problems identified in the licensee's problem report system, the inspectors discussed with the Procurement Manager the broader implications of these issues and the need for better procurement support. The Procurement Manager has directed the formation of a "Procurement Process Re-Engineering Team" to reassess the procurement system and processes and to develop the necessary corrective actions. The inspectors also noted that the licensee's problem report system was effective in identifying the above additional examples where the procurement support of operations and maintenance needed improvement.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (40500, 71707)

6.1 Customized Inspection Planning Process Follow-up

The Customized Inspection Planning Process (CIPP), Inspection Report Nos. 50-334/94-81 and 50-412/94-81, and the recent Systematic Assessment of Licensee Performance, SALP Report Nos. 50-334/93-99 and 50-412/93-99, concluded that the licensee's past processes for identifying human performance problems in a timely manner were not completely effective. Identification of problems was found to be inconsistent because of a high threshold for reporting problems and the evaluation and trending of recurring problems were informal. Additionally, the plant staff was slow in performing corrective actions and responding to findings and recommendations from the Quality Services Unit (Quality Assurance) and other review groups.

The licensee acknowledged the programmatic weaknesses and took steps to strengthen overall performance. By letter dated April 24, 1995, the licensee summarized the corrective actions and program upgrades taken in the areas of management involvement, human performance improvement plan and problem identification\analysis\resolution.

During the period September 18-22, 1995, an interim check on the licensee's progress in making process improvements was performed using the guidance contained in Inspection Procedure 40500 by a group of three inspectors from the regional and headquarters staff.

6.1.1 Management Involvement

Management involvement in routine daily operations was found to be very strong. Morning plant status meetings were chaired by the Plant Manager, with senior management actively participating in establishing safety significance of current issues and on-going tasks. Senior management maintained oversight of plant status, identified certain low-threshold incidents that were escalated to a Problem Report for a more rigorous evaluation, and redirected certain activities to provide for a more conservative system configuration. Management was found to maintain an oversight of emergent issues, a questioning attitude of information presented, and early recognition of potential problem areas. For example, when one instrument air compressor was down for repairs, the inspectors observed management direct that surveillance testing of an emergency diesel generator in the redundant train be deferred to assure full train availability during the repair activity.

Senior management's expectations regarding management involvement in promptly resolving issues and taking a conservative decision-making approach is well articulated in the Nuclear Power Division Business Plan. Organizational goals and objectives are clearly defined and the "Top Ten" management issues are unambiguously stated with management being held accountable for meeting the objectives. In carrying out the plan, senior management implemented an action plan to communicate actions and assignments concerning reinforcement of conservative decision-making throughout all management levels in the Operations, Maintenance, and Training Departments. Specific items address training, personnel selection/qualification, performance evaluations and communications. To ensure that the required actions were taken and to assess the initial effectiveness of these actions in the affected departments, senior management requested that the Quality Services Unit perform a follow-up review. QSU completed the audit in July 1995. The audit concluded that the actions taken have been effective in promoting conservative decision-making. Actions have also been taken to further enhance site-wide awareness and understanding of this subject through steps such as shop meetings, department meetings, daily planning meetings and site-wide communications.

In response to these recommendations, widely promulgated site publications, the Beaver Valley Views and the Operations Experience Group Journal, have increased the scope and depth of articles to highlight examples of conservative and non-conservative decisions made on-site and at other facilities to reinforce management expectations.

6.1.2 Problem Identification/Analyses/Resolution Program

6.1.2.1 Operations Experience Department

The Operations Experience Department (OED), within the Nuclear Operations Unit, is responsible for prioritizing and processing Problem Reports and coordinating with the affected departments analysis of events and development of corrective actions. Management of the affected departments is to ensure that a root cause analysis is performed and that the corrective actions identified receive OED concurrence. Additionally, data associated with each problem report is tracked and trended by OED to identify negative trends in plant operations to establish the underlying causes.

In reviewing the effectiveness of the OED, the inspectors determined that the OED is established on a sound procedural basis with clear lines of reporting and well-defined responsibilities. OED is staffed by eight Shift Technical Advisors (STAs), who in addition to their on-shift responsibilities and training assignments, process problem reports as a collateral duty. Due to the management emphasis on lowering the threshold for problem identification and the resulting large influx of problem reports generated, the OED staff is challenged to process problem reports in an efficient manner. The OED staff has aggressively responded to their tasks, normally closing problem reports within the targeted 60 day period. Since January 1995 through September 18, 1995, 775 problem reports have been generated site wide, with 692 of these being closed, and 83 PRs remaining open.

Problem reports received by OED are initially classified as a Level 1 or a Level 2, based on the judgement of the Supervisor, Reactor Engineering, and then assigned to an STA for follow-up actions. Level 1 Problem Reports are generated for incidents of minor safety significance whose apparent cause requires no further indepth analysis to prescibe corrective actions. Level 2 problem reports normally receive a root cause analysis (RCA). During the investigation of a Level 2 event, reviews of a problem report history file (a computer-based cause code search) are conducted to determine if similar events have occurred in the past. Level 2 reports determined to result in a Licensee Event Report (LER) notification receive additional multi-disciplinary review with additional corrective actions that are separate from the originating problem report and associated Open Item Resolutions (OIR). Presently, Probabilistic Risk Analysis data is not formally used to prioritize problem reports or corrective actions, although this data is retrievable from a computerized database. Upon determining that a problem report is properly completed and that the corrective action items are identified and tracked in the OIR system, the Report is closed by the Manager, Operations Experience. OIRs are tracked separately for closure timeliness.

The inspectors review of completed and in-progress PR's found them to be commensurate with the safety significance of the problem identified. Final quality in addressing the scope/depth of problem resolution was left to STA judgement and time constraints. Since specific criteria have not been developed for classifying repetivitive level 1 problems as level 2 problems research into similar problems is dependant on individual initiative and recall. Although the STA's have a demanding task processing problem reports and performing root cause analyses as a collateral duty, through individual effort, problem reports are being appropriately processed.

The inspectors determined that the STAs were challenged to perform all the root cause analysis for Level 2 problem reports due to the large number of reports generated. For many PR's, additional time was needed to learn a plant system or process before the problem could be adequately resolved and corrective actions addressed. Management and affected departments were not providing feedback on what level of detail was expected to facilitate the efficient use of STA resources.

The inspectors concluded that, overall, an effective problem reporting program has been established to identify and resolve low threshold incidents. Licensee management is aware of program limitations and is evaluating measures to refine PR processing.

6.1.2.2 Root Cause Analysis Program

The team evaluated the licensee's system for root cause analysis (RCA) by: (1) reviewing administrative procedures and departmental implementing guidance for preparation of problem reports (PRs); (2) reviewing completed and in-progress (PRs) and their associated root cause analyses (RCAs); (3) interviewing a number of shift technical advisors (STAs) and line organization managers with RCA responsibility to determine how effectively the RCA process was being implemented; and (4) reviewing the RCA training lesson plans, interviewing the RCA training coordinator and verifing that line organizations did have a number of staff with adequate RCA training.

Overall, the inspectors found the licensee's RCA system to provide a balanced method for identification of both equipment and human performance weaknesses which should provide adequate means of identifying causes of problems and associated corrective actions. Administrative procedures and implementing guidance provided adequate guidance for the use of the system.

The inspectors reviewed the licensee's lesson plans and RCA training documentation and determined that the training materials were thorough and provided an adequate "hands on" approach to understanding event and causal factors charting and causal factors tree evaluations. Licensee training personnel appeared knowledgeable of the RCA process.

A review of selected licensee training records verified that at least one RCA coordinator for each line organization had completed the two-day training program, and most line organization managers had completed at least a 4-hour introductory course, with others scheduled for upcoming training.

6.1.2.3 Tracking & Trending Problem Report Data

The inspectors discussed the methods for tracking and trending problem report data with the Operating Experience Department (OED) staff and reviewed current Open Item Resolution (OIR) database information to determine how effectively the licensee was monitoring the information collected. The inspectors sampled a number of problem reports to verify that the root cause analyses and corrective actions requiring line organization attention were appropriately recorded in the OIR database and were dispositioned in a timely manner. In instances where corrective actions required additional follow-up by line organizations, the actions were documented and adequately recorded in the database and the problem report files. Additionally, the OED staff periodically generated PR status reports which provided numbers of PRs generated, closed, overdue, or approaching their due date. Overall, the inspectors found that the licensee had an adequate process for tracking and trending corrective action information.

6.1.2.4 Problem Report Trend Analysis

The inspectors reviewed the last two Operating Experience Department (OED) quarterly performance trend reports to determine what performance weaknesses were identified by the licensee's problem report system and what corrective actions had been implemented or planned as a result of this information. Based on the reports, it appears that the human performance problems are dominated by weaknesses in work practices (*i.e.*, lack of self checking or failure to follow procedures), configuration control (*i.e.*, drawings or procedures not in conformance with as-built design or equipment not in normal system arrangement), and written communications (*i.e.*, procedures).

The inspectors, discussed these findings with various line organization managers and reviewed various corrective actions proposed or implemented by these groups. In general, it appeared that the licensee had taken steps to correct these performance weaknesses by increasing oversight of work by supervisors during routine operations surveillances, disseminating management expectations regarding self-checking through various department memoranda and training instructions, and monitoring performance trends through department self-assessment programs. However, several managers and a number of licensee staff did not recall having seen the quarterly reports, or were not aware of proposed or implemented corrective actions resulting from the reports.

6.1.2.5 Scope and Timeliness of Corrective Actions

The inspectors determined that the licensee has implemented corrective actions to reduce Open Item Resolutions (OIRs) and associated station engineering and maintenance backlogs. Senior management has communicated their expectations to department managers regarding the timeliness of addressing overdue open items and routinely review station performance through monthly performance reports. Lower level management monitors their backlogs through various monthly departmental reports and performance indicators which enhances their ability to identify and address problem areas.

Over the past year, senior management has increased their attention regarding the timeliness and effectiveness in addressing overdue problem resolution. These expectations are being communicated to the site staff by senior management through staff communication meetings and in-plant tours. Also, monthly performance indicators and OIR status reports are now receiving increased attention to senior management.

The inspectors reviewed various backlogs and determined that the level of overdue items is going down. The corrective maintenance backlog has decreased since April from about 2600 to about 2000 non-outage items. The Maintenance Program Unit (MPU) has been closing about 27 corrective maintenance items per day and generating about 25 per day. Engineering's Maintenance Commitment Tracking (MCT) backlog has significantly decreased from 709 items to 461 items. Of these items, those that were overdue dropped from 190 items (102 items being greater than 90 days old) in January 1995, to 55 items (19 items being greater than 90 days old). Management is considering implementing a "fix-it-now" special team to expedite reduction of the minor maintenance backlog.

6.1.3 Human Performance Improvement Plan

The inspectors evaluated the corrective actions implemented by the licensee to address concerns identified in the area of human performance. Self-checking, attention to detail, and supervisory oversight of work activities received the main focus of review. The team reviewed documents and interviewed personnel in the MPU group and Operations Department.

6.1.3.1 Supervisory Oversight and Review

The inspectors determined that management's emphasis on performance standards and personnel accountability increased since the beginning of 1995. Each department developed and implemented a human performance improvement plan which defined expectations and set goals to improve human performance. Management routinely communicated expectations, the need for heightened problem awareness, and self-checking practices to all employees at staff communication meetings. Senior management and department heads have established formal processes to consistently identify, review, analyze, and trend human performance and the material condition of the plant. Goals and performance indicators have been established.

The MPU group established the "MPU Work Standard Surveillances" program in March 1995. This formalized program provides supervisory oversight and review of work activities to assure management's expectations and performance standards are being met. Each supervisor is required to overview a minimum of three surveillances per month using a work practice surveillance checklist. Supervisors communicate to technicians, reinforce performance standards, and correct individuals demonstrating less than acceptable work practices. Problem reports and STOP safety cards are initiated if safety or radiological problems are identified.

The inspectors determined that the Work Standard Surveillance Program has been effective. Approximately 98% of the surveillances scheduled since April 1995 have been performed. The initial focus of findings identified during this period have concerned the material condition of the plant and housekeeping. However, with observed improvement in the plant's material condition, management has provided guidance for supervisors to become more focused on identifying human performance and work practice issues.

The Operations Department management has also established a program for supervisory monitoring of operator activities. The control room supervisors are encouraged to spend an average of 2 hours per shift observing operator activities and conducting plant inspections. The supervisors use the guidance given in NPDAP 8.1, "Work Activity Surveillance Program," and NPDAP 8.8, "Plant Inspection Program," during their tours. The program is controlled as a management expectation to provide the program the flexibility to conform to each shift supervisor's schedule. The Operations Manager monitors the program to ensure that all supervisors comply with his expectation. The team noted that the shift supervisors interviewed were aware of management's expectation and actively participated in the program. The team noted that the control room log reflected the supervisor's tour, including the time duration of the tour, areas visited, and major observations. The team determined that the tours are being effective as evidenced by the many problem reports or maintenance work requests initiated by supervisors from their observations.

6.1.3.2 Self-Checking and Attention to Detail

The team determined that the licensee is establishing a strong self-checking program which is used throughout the facility. The program was initially developed by the manager for the Instrument and Controls (I&C) section of MPU and has become the model for the other departments self-checking programs. Observed reduction in safety significant events involving human error has resulted due to self-checking techniques. Senior management has demonstrated an active involvement and commitment in promoting self-checking and has continued to reinforce their expectations for the site staff to continue to employ self-checking techniques.

All maintenance and operations personnel have been trained in self-checking practices. Reinforcement of management expectations occurs during staff communication meetings and by the supervisory presence in the plant during work activities. Also, senior management routinely tour the facility on a regular basis which communicates their expectation for improved performance.

The team observed a decline in work related errors for safety-related systems. However, management has recognized that this good performance is not as well demonstrated in all non-safety-related activities. It is management's goal to heighten "situation awareness" and promote self-checking as more than a tool. The "situation awareness" concept is to improve the consistency of self-checking in every situation and become more of a habit.

6.1.3.3 Procedure Upgrade Program

Steady progress has been made by the licensee's Procedure Upgrade Project to incorporate human factor considerations into revised and updated procedures to improve site-wide consistency and ease of use. Priorities have been established focusing on what procedural categories receive precedence for complete upgrading. Procedure content is being improved through use of a "Procedure Writer's Guide," which standardizes procedural format, highlights logic words, delineates coordinating actions, and emphasizes precautionary statements. The reduction of the backlog of procedure changes is meeting an established schedule and receives frequent management attention.

6.1.3.4 Conclusion

The team concluded that the licensee has implemented a good human performance improvement program. The plan includes a strong self-check and attention to detail program. Senior management involvement and commitment to these programs is continuing to heighten staff awareness of performance and work practice expectations.

6.1.4 Self-Assessments

6.1.4.1 Departmental Self-Assessments

The team reviewed a sample of line organization and Operational Experience Department self-assessments to determine how effective the organizations were at identifying their own performance weaknesses. Overall, the team considered the licensee's processes for self-assessments to be adequately documented in administrative procedures and implementing guidance. A sample of self-assessment reports were reviewed and found to thoroughly and candidly document performance weaknesses and planned corrective actions. Follow-up assessments were noted to further document and trend performance weaknesses and to assess the effectiveness of corrective actions taken. In addition, the staff reviewed the licensee's schedule for self-assessments for 1995. The team noted that several self-assessments scheduled for or already completed, focused on identified major performance weaknesses, such as work control and self-checking. A self-assessment regarding the effectiveness of the RCA evaluation process is scheduled for the fourth quarter of 1995.

6.1.4.2 Quality Services Unit Audits

Several recent Quality Services Unit (QSU) audits were reviewed to evaluate the effectiveness of the licensee to monitor performance of the Operational Experience Department and to correct identified programmatic deficiencies. Audits were found to be very detailed, having the scope and depth necessary to assess procedural adequacy and personnel performance in carrying out the Corrective Action Program. Areas for improvement were identified with recommendations clearly stated. Past recommendations that were provided in previous audits to which supervision did not respond in a timely manner were escalated to deficiencies, receiving senior management attention.

6.1.4.3 Engineering Assurance Program

The team reviewed the licensee's Engineering Assurance Review Process and found it be an adequate approach to both identifying performance problems in the engineering area, as well as analyzing current performance to determine positive and negative effects of corrective actions. The use of multiple input mechanisms including internal audits of on-going work, review of On-site Safety Committee (OSC) findings regarding the Nuclear Engineering Department (NED), review of engineering assurance reports regarding engineering change notices and field change notices, and the analysis of problem reports and NED root cause analyses was seen as a strength.

Additionally, the team reviewed a sample of the NED root cause analyses and found these reports to be well-documented, thorough reviews of the specific problem areas.

6.1.5 Inspection Summary

Through aggressive management involvement and close monitoring by the Quality Services Unit, the licensee's Corrective Action Program is evolving into an effective management tool for promptly identifying, thoroughly evaluating, and effectively resolving low-threshold problems. Past programmatic weaknesses are being systematically addressed by the appropriate level of management and subsequent corrective actions have strengthened problem recognition and resolution capabilities.

6.2 Part 21 Report on Fasteners Supplied by Cardinal Industrial Products (Closed)

Duquesne Light Company has an overcheck program for all 10 CFR 50, Appendix B supplied fasteners. On May 3, 1995, this overcheck program identified defective safety-related hex head cap screws supplied by Cardinal Industrial Products. The defective screw material failed the tensile and yield strength requirements for ASTM A193 Grade B7 material. In late July, Duquesne Light Company personnel witnessed additional testing, at Cardinal, of screw material from the lot with the previous failures. One of four samples selected for the tests failed to meet minimum tensile strength requirements. On August 29, after further investigation, Cardinal made a 10 CFR Part 21 report to the NRC concerning defective fasteners. Three lots of fasteners were identified in the report as potentially defective due to improper heat treatment.

The inspectors reviewed this issue with the licensee, and determined that the licensee's actions to identify, pursue and report the failed fasteners were appropriate. The fastener overcheck program was considered a noteworthy initiative. The licensee determined that the defective fasteners that would have adversely effected the function of plant components were not installed in any locations at Beaver Valley. This issue is closed at Beaver Valley.

7.0 ADMINISTRATIVE

7.1 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 October 16, 1995, with Beaver Valley management summarizing inspection activity and findings for this period.

Preliminary inspection finding exits were held on September 22 by T. Moslak in the area of human performance and problem resolution, and on September 29 by R. Struckmeyer in the area of environmental and meteorological monitoring. In addition, a preliminary inspection finding exit for NRC Inspection Report

95-18, the follow-up inspection of the licensee's service water system operational performance (SWOPI) self-assessment, was held on October 5, 1995, by M. Buckley.

7.2 NRC Staff Activities

Inspections were conducted on both normal and backshift hours: 22 hours of direct inspection were conducted on backshift; 19 hours were conducted on deep backshift. The times of backshift hours were adjusted weekly to assure randomness.

P. Eselgroth, Chief, Projects Branch 7, NRC Region I, visited the site on October 3 and 4, 1995, for discussions with the inspectors and utility management, and to tour the site.