U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	Duquesne Light Company (DLC) Post Office Box 4 Shippingport, PA 15077
Facility:	Beaver Valley Power Station, Units 1 and 2
Inspection Period:	December 22, 1996 through February 8, 1997
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EXECUTIVE SUMMARY

Beaver Valley Power Station, Units 1 & 2
NRC Inspection Report 50-334/96-10 & 50-412/96-10

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection; in addition, it includes the results of a nation-wide review of criticality monitoring in new fuel storage areas performed by the Office of Nuclear Reactor Regulation.

Operations

- From September to early December 1996, the morning management meetings were often ineffective for communicating and managing plant issues. During this inspection period the Senior Vice President-Chief Nuclear Officer and the Plant Manager met with various managers and clearly expressed their expectations on key issues including control of vendor work, issue management and accountability, limiting condition for operation maintenance, and control room deficiencies. The conduct and effectiveness of the morning management meeting has improved throughout this inspection period. Managers have more readily taken responsibility to manage safety issues and equipment problems at an appropriate level without prompting from senior management. (Section O1.2).

- On January 6, Unit 2 tripped from 98% power due to a main transformer protection relay actuation. Operators responded appropriately to the reactor trip and the unit was stabilized. Numerous secondary problems occurred before and after the reactor trip; however, they did not cause the reactor trip or complicate the recovery. The Event Review Team (ERT) generally evaluated all outstanding issues associated with the reactor trip properly. The shift technical advisor and Independent Safety Evaluation Group (ISEG) provided effective reviews of the post trip data (Section O1.3).

- The inspectors noted effective communications and good control during the January 14 Unit 2 reactor startup. A source range alarm during control rod withdrawal was handled appropriately, although operator knowledge and the alarm response procedure were weak. Overall startup activities were conducted safely (Section O1.4).

- A small leak from the Unit 2 B safety injection accumulator into the residual heat removal system (RHS) necessitated frequent RHS system depressurization. The system engineer provided an appropriate basis for continued operation. Operations and chemistry personnel failed to properly implement station procedures when depressurizing the RHS system from January 23 to January 30, 1997. Operations personnel identified and corrected this procedural adherence deficiency on January 30 (Section O1.6).

- From September 1996 to February 1997, the licensee identified numerous components out of normal switch alignment (NSA) position. Although the licensee demonstrated a low threshold for identifying component misconfigurations and

initiated several comprehensive corrective actions during this inspection period, the inspectors determined that previous corrective actions initiated to address similar problems in 1995 had been ineffective. Poor work practices and operator errors including failure to properly implement written procedures continued to result in configuration control problems. Failure to maintain adequate configuration control was an apparent Violation (Section O1.7).

- Non-safety significant control room deficiencies continued to accumulate in backlog during 1996, which in the aggregate, made operator duties more difficult to perform. Deficiencies were not actively managed and routinely exceeded the station goals. In December 1996 and January 1997 management placed a higher priority on promptly correcting control room deficiencies and clearly delineated responsibilities. The actions taken and initial results were positive in reducing the number and duration of control room deficiencies (Section O2.2).

- The Unit 1 waste gas decay tank (WGDT) oxygen analyzers were inadvertently deenergized on November 25 due to operator error and inadequate operator logs. Previous corrective actions to address improper operation of the WGDT power switch and pressure switch override control switch were ineffective. Licensee investigation of this event was detailed and comprehensive. The licensee event report (LER) accurately documented the event (Section O4.1).

- Communications errors between operators and procedure weaknesses resulted in the failure to perform a Technical Specification required quadrant power tilt ratio surveillance for Unit 2 on December 20, 1996. Causal assessment and corrective actions were comprehensive and properly implemented. The LER accurately described the event in appropriate detail and met the reporting requirements of 10 CFR 50.73 (Section O8.2).

- On January 15, station management held reactor power at 30% during power ascension to evaluate a potential water hammer issue with the recirculation spray system. Engineers performed an evaluation and short term compensatory measures were in place prior to commencing a load increase to full rated power. The long-term corrective actions were still being evaluated at the end of the period. The inspectors observed that management response to industry information regarding this issue was proactive and comprehensive (Section O8.4).

- The Operations department developed a detailed discussion paper regarding the January 11, 1997 Unit 2 recirculation spray system operability determination. This was an excellent teaching tool developed to enhance operators' skills regarding operability determinations (Section E2.1).

Maintenance

- Beaver Valley Unit 1 and Unit 2 experienced numerous freeze protection problems this winter. Although safety related equipment problems were minimal, the failures resulted in an increased burden on the operations staff. The licensee failed to

adequately address the problems identified in a QA audit and an NRC inspection report. Corrective actions, although not fully implemented, appear appropriate to address the current problems. Determination of whether Unit 1 reactor water storage tank heat traced lines are properly designed is an unresolved issue (Section M2.1).

- Prior to the reactor trip on January 6, Unit 2 experienced a secondary system transient as a result of lack of quality workmanship. The transient and additional secondary system problems did not cause the reactor trip or adversely impact the operators' ability to place Unit 2 in a safe shutdown condition after the reactor trip. The corrective actions to address the failures were appropriate (Section M2.2).

Engineering

- Development of additional auxiliary river water pump performance criteria for maintenance rule trending and risk assessment was a positive initiative by the system engineer (Section M1.2).

- The licensee evaluation of the Unit 2 trip was of sufficient depth to accurately determine the root cause (inadequate original design implementation). Although the main transformer ground protection relay is not described in the UFSAR and is not a safety related Appendix B criteria component, the failure to adequately implement the original design is a noted weakness. Corrective actions generally addressed this weakness (Section E1.1).

- Original Unit 2 construction deficiencies resulted in missing/defective recirculation spray (RS) pump flood seals. On January 11, both RS trains were declared inoperable and mode 5 was entered as required by technical specifications. The inspectors determined that engineer persistence in investigating potential sources of water inleakage and the new UFSAR word search capability were instrumental in identifying the flood seal deficiency and developing an appropriate operability determination. Engineers demonstrated a detailed knowledge level regarding RS flood seals and the repairs were of good quality (Section E2.1).

- On January 28, 1997, operators found the EDG 2-1 governor cooling water outlet valve (2EGS-19) 95% shut instead of full open. The valve was promptly repositioned and the EDG was successfully tested to verify operability. The inspectors questioned whether the EDG had been capable of performing its design accident mitigation function with 2EGS-19 in the 95% shut position. The inspectors determined that the initial engineering evaluation did not contain sufficient detail to resolve the issue. The licensee reopened the engineering evaluation for further analysis. Long term operability remains an unresolved issue (Section E2.3).

- Failure to have the required criticality alarm system installed to monitor the Unit 1 new fuel storage area, or to have a valid exemption from the criticality alarm requirements of 10 CFR 70.24, was a violation (Section E8.1).

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- The inspector found the corrective actions in response to LER 96-06, "Potential Control and Protection System Interaction in Steam Generator Water Level Control," to be extensive and ensure compliance with IEEE-279. Engineers and procedure writers effectively addressed all immediate concerns associated with the control and protection system interaction during calibrations of the affected channels (Section E8.2).

Plant Support

- From December 26, 1996, to February 7, 1997, several valves and switches were found out of their normal switch alignment (NSA) position. Station personnel demonstrated a very low threshold for identifying components out of NSA and treating them as potential tampering events until reasonably proven otherwise. Security compensatory measures and investigations were timely and thorough. Potential tampering procedures were comprehensive, and no indication of tampering was identified. Operator requalification training plan revisions to incorporate additional insight on potential tampering issues were excellent (Section S1.1).

- On January 24, 1997, a fire main ruptured underground causing a water stream to shoot upward from beneath the ground near the protected area perimeter. Intrusion detection alarms were received and erosion degraded the sloping ground embankment along one side of the security perimeter. Security response to the ruptured fire main and degraded security perimeter were excellent. Compensatory measures were appropriately maintained through the end of the report period and security officers remained alert to their duties (Section S2.1).

Safety Assessment and Quality Verification

- On January 1, 1997, a new condition report (CR) corrective action program was established. It was implemented throughout the inspection period without significant problems. The program was consistently administered with issue follow-up clearly assigned to specific managers at the daily morning management meeting. The objectives of the CR system were reasonable for improving deficiency identification, resolution, and tracking. Additional assessment would not be appropriate until the program has established a longer history (Section O1.5).

- A previously unresolved inspection finding involved certification of vendors to perform safety related work. Inspector follow-up concluded that station procedures were inadequate to assure vendors met qualified suppliers list requirements prior to performing safety related work. As a result, a vendor performed safety related leak injection repair services on December 1-2, 1996 without satisfying applicable quality requirements. This was a violation. Corrective actions initiated to address this issue were appropriate (Section M8.1).

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Report Details

Summary of Plant Status

Unit 1 began this inspection period at 100% power. On December 27-28, 1996, and on January 24, 1997, the unit reduced load for condenser tube inspection and leak repair. The unit returned to 100% power and remained there for the extent of the inspection period.

Unit 2 was completing power escalation to 100% power at the start of the inspection period. The unit reached full rated capacity on January 4, 1997, after repairs to a moisture separator drain receiver drain pump were completed. On January 6, 1997, the unit tripped due to a turbine trip caused by a main transformer backfeed ground protection relay. The outage was extended to replace missing flexible boot flood seals for the recirculation spray pumps. The seals were replaced, and Mode 1 was entered on January 14, 1997. Operators maintained the reactor below 30% power to evaluate a potential recirculation spray pump water hammer issue. The unit resumed power escalation and reached full rated power on January 17, 1997, and remained there for the extent of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)[1]

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious, specific events and noteworthy observations are detailed in the sections below.

O1.2 Daily Management Meeting and Management Expectations

a. Inspection Scope (71707)

The daily management meeting is conducted each morning to discuss current operational plant status, safety issues, and planned work. The inspectors observed the meetings to assess whether significant information was effectively communicated and acted upon.

b. Observations and Findings

During the September through early December 1996 timeframe the inspectors had observed that the morning management meetings were often ineffective at communicating and managing plant issues. Although the meetings typically lasted

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[1]Topical headings such a O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

over an hour, various managers were often unprepared to discuss equipment operability concerns and problems reported the previous day. Ownership for issue resolution did not appear to be consistently assigned and understood. Some examples included emergency diesel generator maintenance and testing, cold weather preparations, and various equipment deficiencies. Questioning by the Senior Vice President - Chief Nuclear Officer (SVP-CNO) was often necessary to ensure safety and operability concerns were properly addressed at the meeting.

In December and January the SVP-CNO held several seminars with managers following the morning meeting to clearly define his expectations for how issues should be managed. Vendor ownership was clearly highlighted to assure lessons learned from recent vendor work problems were understood. Manager accountability for issue ownership, resolution, and appropriate timeliness were key topics.

Throughout this inspection period, the inspectors noted that the conduct and effectiveness of the morning management meetings improved. In most instances, department and general managers were well prepared and took a more active role in discussing safety issues for which they were responsible. The condition report program which began on January 1, 1997, was consistently administered with issue follow-up clearly assigned to specific managers. Operations management clearly identified work priorities and demanded support to resolve ongoing equipment problems. On several occasions the Nuclear Shift Supervisors (NSSs) demonstrated proactive risk management insights and postponed scheduled work activities. The inspectors observed that the shift test advisors and NSSs were properly implementing station procedures to assess the risk associated with combined equipment outages.

In late December, the inspectors observed that some planned limiting condition for operation (LCO) maintenance activities on safety related equipment took much longer than planned. Examples included corrective maintenance on 2HVC-ACU201A, which took 5 days of a 7 day LCO-allowed period, and preventive maintenance on two Unit 1 recirculation spray pumps (RS-P-1A/2A), which took 12 hours although planned for only one hour. In each case, the work was completed within the time permitted by TS. However, these examples indicated a need to better manage LCO maintenance activities. The inspectors discussed these observations with operations management. No further examples of extended LCO maintenance were observed during this inspection period. In late January, the new Plant Manager expressed his expectations to all managers that LCO maintenance be worked around the clock and control room deficiencies be given a high priority.

c. Conclusions

From September to early December 1996, the morning management meetings were often ineffective for communicating and managing plant issues. During this inspection period the SVP-CNO and the Plant Manager met with various managers and clearly expressed their expectations on key issues including control of vendor work, issue management and accountability, LCO maintenance, and control room deficiencies. The inspectors observed that the conduct and effectiveness of the

morning management meeting improved throughout this inspection period. Managers have more readily taken responsibility to manage safety issues and equipment problems at an appropriate level without prompting from senior management.

O1.3 Unit 2 Reactor Trip

a. Inspection Scope (71707, 92901, 93702)

The inspectors reviewed DLC's response to the Unit 2 turbine trip and subsequent reactor trip that occurred on January 6, 1997. The inspectors examined plant response to the reactor trip, events prior to the reactor trip, and the investigation into the cause of the trip.

b. Observations and Findings

On January 6, at 5:56 a.m., Unit 2 tripped from 98% power due to a turbine trip. The turbine trip was caused by an actuation of a main transformer backfeed ground protection relay. Operators responded appropriately, and the unit was stabilized in Mode 3 (hot standby) for post-trip review and analysis. The reactor trip was reported within 4 hours to the NRC as required by 10 CFR 50.72(b)(2)(ii).

The plant safety systems responded as designed during the trip; however, multiple secondary system problems occurred. Prior to and unrelated to the trip, problems associated with the moisture separator reheaters (MSRs) and the heater drain systems resulted in isolation of all MSRs and reduced flow from one train of the heater drain system. After the reactor trip, six condensate and feedwater relief valves lifted and failed to reseat.

An Event Review Team (ERT) was established to review the events and to provide recommendations to the Nuclear Safety Review Board (NSRB). The inspectors attended various ERT meetings and held discussions with members of the ERT team. The use of an ERT for event analysis and review is a newly developed process at Beaver Valley. The inspectors noted that team members were of sufficiently different backgrounds and organizational departments to provide broad review of the event. The ERT generally addressed all the outstanding issues associated with the trip in a thorough manner. Specific issues regarding the main transformer relay and the secondary system problems are discussed in Section E1.1 and E1.2, respectively.

A separate review of the post trip response of the plant protection and control systems was conducted by the shift technical advisor using OEDM 7.10, Rev. 0, "Post Trip Reviews." Independent Safety Evaluation Group (ISEG) conducted an independent review of post trip data and performed a change analysis with respect to past reactor trips at Beaver Valley. No new issues were identified by the reviews. The inspectors noted the reviews provided effective means of identifying any abnormal safety or non-safety related system responses.

c. Conclusions

Operators responded appropriately to the reactor trip and the unit was stabilized. Numerous secondary problems occurred before and after the reactor trip; however, they did not cause the reactor trip or complicate the recovery. The ERT generally evaluated all outstanding issues associated with the reactor trip properly. The shift technical advisor and ISEG provided effective reviews of the post trip data.

O1.4 Unit 2 Reactor Startup and Power Escalation

a. Inspection Scope (71707)

The inspectors observed startup activities in the Unit 2 control room on January 14. The startup commenced following completion of repairs to the recirculation spray pump boots and corrective actions from the reactive trip due to the main transformer relay. The inspectors noted strong command and control of the startup evolution. The inspectors also observed good communications between reactor operators, the reactor engineer, and system engineers.

b. Observations and Findings

On January 14, DLC conducted a reactor startup on Unit 2. During the actual startup evolution, distractions to the reactor operators were minimized. Reactor engineering support and communications to the operating staff were very good. Independent checks of reactor engineering by the shift technical advisor demonstrated sound work practices. The inspectors noted one weakness. While withdrawing control rods to reach criticality, a "source range flux doubling" alarm was received. The inspectors observed that operator knowledge of the alarm and the alarm response procedure were weak. The withdrawal of control rods was temporarily halted. An operations supervisor determined that the alarm was appropriate and that it would clear after 10 minutes. At that time, the alarm cleared and startup was resumed. After discussions with operations management, the inspectors determined that long term corrective actions would address the alarm response procedure and that there were no safety concerns. The Unit 2 reactor startup was completed without incident. The inspector observed that appropriate safety precautions were observed throughout the startup evolution.

c. Conclusions

The inspectors noted effective communications and good control during the Unit 2 reactor startup. A source range alarm during control rod withdrawal was handled appropriately, although the inspectors noted that operator knowledge and the alarm response procedure were weak. The inspectors concluded that overall startup activities were conducted safely.

O1.5 Implementation of Condition Report System

a. Inspection Scope (71707)

Inspectors reviewed the implementation of the Condition Report (CR) system by DLC. The CR system replaced the Problem Report system on January 1 as DLC's primary corrective action system for identifying, resolving, and preventing problems.

b. Findings and Observations

On January 1, DLC implemented the Condition Report (CR) system to document the identification and resolution of deficiencies at Beaver Valley and the subsequent corrective actions taken to prevent recurrence.

Background
At the end of 1993, in response to declining trends in plant operations, personnel performance, and a noted increase in regulatory issues, violations, and safety concerns, DLC formed two in-house review groups, a Program Review Team and a Performance Review Team. Results of these reviews and responses identifying corrective actions were issued on March 1, 1994.

During the period June 18 - October 7, 1996, the Quality Services Unit (QSU) conducted an audit (Audit No. BV-C-96-05) of the corrective action program. The audit was a technical specification requirement conducted under the cognizance of the Offsite Safety Committee. QSU found that the corrective actions for several of the areas addressed by the Program Review Team in 1994 were not effectively implemented and other areas were only marginally effective. Weak corrective actions were noted in several areas, including establishment of a structured formal root cause analysis program, development of a process for forming event review teams and a corrective action review board, self-assessments, effectiveness reviews, and use of the Commitment Action and Tracking System.

As a result of the QSU audit findings and recommendations, DLC conducted a review of several industry corrective action programs that were highly regarded. Based on the review, DLC chose to design a new system to replace the existing problem report system that would address the audit weaknesses and strengthen the corrective action program. Following tabletop exercises in November and some site training sessions in December, the CR system was implemented on January 1. Additional training sessions were scheduled for January.

CR System
Inspectors attended one of the site training sessions for the CR system, discussed the system with the Condition Report Program Administrator (CRPA), and reviewed the following implementing procedures: Nuclear Power Division Administrative Procedure (NPDAP) 5.2, "Initiation of Conditions Reports," NPDAP 5.6, "Processing of Condition Reports," and NPDAP 5.8, "Root Cause Analysis."

DLC had three main goals in developing the CR system:

(1) replace two previous deficiency reporting systems, the problem report and the quality services deficiency report (QSDR), with a stronger single system;

(2) allow for five categories of evaluation based on the significance of the condition, rather than the two levels under the old system. The intent was to provide a more measured response to problems to focus DLC resources more efficiently; and

(3) provide a strong central administration of the system to enforce consistency and allow easier trending.

At the end of January, about 866 problem reports and about 39 QSDRs were outstanding from the old deficiency reporting systems. DLC expected to continue resolving and closing problem reports and open item requests from the old deficiency reporting system until completion in about early summer. DLC reviewed the outstanding problem reports and all those from the fourth quarter of 1996 using the cause codes of the CR system. The resulting information was then loaded into the computer database established for the CR system for trending. Due dates for evaluations and corrective actions for problem reports remained unchanged following the implementation of the CR system. Overdue items were tracked by the Nuclear Licensing Department, which issued a weekly status report. As of January 24, there were 24 overdue Level 2 evaluations and 9 overdue open item requests. There were no overdue QSDRs.

To administer the CR system, DLC created the position of Condition Report Program Administrator (CRPA). The CRPA reports to the Director of Licensing and has a key position in the CR system. As defined in NPDAP 5.6, among his responsibilities are: (1) establishing the category and due date of CRs, except those initiated by QSU, (2) reviewing CR documentation for adequacy, completeness, and identification of any overdue actions, (3) coordinating and tracking corrective actions, (4) coordinating and tracking effectiveness reviews of corrective actions, (5) entering applicable information into the CR database and performing periodic trend analysis, (6) closure of CRs and their transmittal to records storage, (7) identifying the assigned organization for investigation of CRs, and (8) coordinating reviews of CRs by the licensing and system engineering staffs and the Nuclear Safety Review Board, as applicable.

Another key component of the CR system is expected to be the CR Evaluation and Status Tracking System (CREST), which will replace the Commitment and Action Tracking System (CATS) as the primary deficiency tracking system. CATS was relatively inflexible. As a result, most trending was done by hand, and there was relatively little analysis of data. DLC expects that CREST will allow much easier trending, which should aid root cause analysis. As input to CREST, NPDAP 5.6 requires much more documentation of the CR process, particularly cause analysis and corrective actions, than the old problem report system. At the end of the period, the CREST system was only operable in the Licensing Department; DLC expected to make it accessible site-wide within a month.

NPDAP 5.6 established five categories for CR investigations, from category 1 (a significant condition requiring the highest level of management overview and technical response) to category 5 (a condition generally well-understood, with corrective actions that have been completed or are well underway). The NPDAP provided adequate criteria and examples as guidance in categorizing the condition.

DLC did not change the threshold for initiating a CR from that of the old problem report. For January, 196 CRs were generated, including 29 involving equipment failure and 25 involving human error. No CR action items were overdue.

c. Conclusions

Inspectors concluded that DLC had implemented the CR system without significant problems. The program was consistently administered with issue follow-up clearly assigned to specific managers at the daily morning management meeting. The objectives of the CR system were reasonable for improving deficiency identification, resolution, and tracking. Additional assessment would not be appropriate until the program has established a longer history.

O1.6 Residual Heat Removal Depressurization

a. Inspection Scope (71707, 92903)

Unit 2 experienced leakage from the 'B' safety injection accumulator past a Residual Heat Removal System (RHS) isolation valve, which resulted in pressurization of the 'A' RHS system. The inspectors reviewed the methods and procedures used to depressurize the system, the Basis for Continued Operation (BCO) of the valve, and reviewed applicable technical specifications (TS). The inspectors also reviewed chemistry and operator logs to verify the actual sequence of events. The inspectors discussed depressurization and trending with the system engineer, chemistry personnel, and reactor operators.

b. Observations and Findings

Since the plant outage completed on January 14, 1997, Unit 2 has experienced leakage past the closed and deenergized RHS isolation valve (2RHS-MOV720A). The licensee has observed the leak rate between 0.1 and 1.7 gph. Technical specifications limit the leak rate to 5 gpm at full reactor coolant system (RCS) pressure. The system engineer determined the leak was coming from the 'B' safety injection accumulator based on trending of the accumulator level and pressures in the RHS. Operators have not observed a notable increase in RCS leakrate. 'B' accumulator level has been refilled approximately every 5 to 10 days. The inspector reviewed the BCO and determined it was technically sound.

On January 14, the nuclear shift supervisor instructed chemistry technicians to perform their sampling procedure (Chemistry Manual 2-3.40 Part D, "RHS Grab Sample Purging to Sample Sink," Rev. 6) to depressurize the 'A' RHS system. In parallel, operations personnel requested that a procedure be developed for depressurization. Operators were not aware of an alarm response procedure for

high pressure in the RHS system, which was designed to depressurize the RHS. On about January 20, operators began using the guidance of the alarm response procedure and chemistry technicians continued to use the sample procedure to align the system to depressurize. The system engineer and procedure writers completed a revision to the alarm response procedure on January 22, and placed it in the RHS shutdown procedure (2OM-10.4.C, "Residual Heat Removal System Shutdown," Revision 20) to be used for depressurization of the RHS system. The alarm response procedure was retired at this point. The new procedure was available to operations on about January 23. Based on discussions with the operations management and review of operator and chemist logs, the procedural steps of 2OM-10.4.C were not followed at this point. Operators had reviewed the revised 2OM-10.4.C, but continued to depressurize the RHS relying on their memory of the retired alarm response procedure.

Beginning on about January 23, the nuclear shift supervisor and chemists agreed to leave the sampling valves open and allow operators to open the containment isolation valve when they needed to depressurize the RHS. The chemistry procedure would be entered and remain entered until a sample on a different line (e.g. RCS hot leg sample) was obtained. After the other sample was taken, the chemists would return the RHS valves to their drain position. The agreement gave operators additional flexibility to perform the frequent draining operation and to attempt to minimize leakage.

On January 29, the control room operator opened the containment isolation valve to depressurize the RHS. The nuclear shift supervisor identified that the expected rapid decrease in RHS pressure did not occur and contacted chemistry to verify valve lineup. A chemist found a valve throttled vice opened as described in the chemistry procedure for RHS sampling. The chemist repositioned the valve and the RHS depressurized. This revealed problems with the following:

- Chemists improperly entering multiple procedures. Station procedures do not provide this latitude.

- Failure by chemists to properly perform steps called out in their procedures.

- Failure by operators to properly perform the steps specified in procedure 2OM-10.4.C after this was identified as the correct procedure to use. Operators relied on memory rather than performing the procedure which required sign-off for step-by-step completion.

- Possible communication problems between Operations/Chemistry shift personnel.

The inspectors noted that the above problems changed the configuration control of the RHS sampling system. The inspectors observed that the ability to provide containment isolation and to monitor the TS limits on leakage into the RHS system was maintained at all times. On January 30, the Technical Assistant to the General Manager-Nuclear Operations required that all future depressurizations be completed

by the approved depressurization procedure in 2OM-10.4.C, "Residual Heat Removal System Shutdown," Revision 20. Corrective actions to the above problems are being developed under Condition Report 97-0289.

TS 6.8.1 requires written procedures to be established and implemented covering activities recommended in Appendix A of NRC RG 1.33, revision 2. Contrary to the above, during the period January 23 to January 28, 1997, operators and chemistry technicians failed to properly implement station procedures (CM 2-3.40 Part D, "RHS Grab Sample Purging to Sample Sink," Rev. 6; 2OM-10.4.C, "Residual Heat Removal System Shutdown," Revision 20; and 1/2 OM-48.2.C "Adherence and Familiarization to Operating Procedures," Revision 17) when repeatedly depressurizing the Unit 2 RHS system. This issue along with additional configuration control problems are addressed as a group in Section O1.7.

c. Conclusions

Unit 2 experienced a small leak from the B safety injection accumulator to the RHS system which necessitated periodic RHS system depressurization. The system engineer provided an appropriate BCO. Operations and chemistry personnel repeatedly failed to properly implement station procedures for RHS depressurization from January 23 to January 30. The licensee identified and corrected this procedural adherence deficiency on January 30.

O1.7 Configuration Control Problems

a. Inspection Scope (71707, 92901, 92903)

From September 1996 to February 1997, DLC identified numerous components out of normal switch alignment (NSA) position. Immediate actions were taken to address the potential for deliberate tampering, as described in Section S1.1. The inspectors reviewed logs, interviewed personnel, and met with management to assess the magnitude of the problem, causes, and corrective actions.

b. Observations and Findings

Background
A NRC team inspection was conducted at Beaver Valley in July 1995 to investigate several instances of mispositioned components and evaluate perceived weaknesses in timely security follow-up for potential tampering concerns. The team did not find evidence of potential tampering, but configuration control issues were raised (Unresolved Items 412/95080-01 and 334(412)/95080-04). Specifically, the team noted weaknesses in procedural adherence during independent verifications and agreed with DLC findings that the mispositionings most likely resulted from poor work practices or operator error. DLC initiated several corrective actions including departmental valve lineup verifications to ensure that controlled drawings, system line up procedures, and actual in-plant alignments were consistent. The inspectors reviewed the chemistry department results, completed December 13, 1995, which verified over 1100 valves. Four valves were found out of the correct position, and

69 valves were found in the correct position, but required procedure revisions to reflect the correct as-found position.

Current Issues

From September 1996 to February 1997, DLC identified numerous components out of normal switch alignment (NSA) position. The inspectors reviewed component misalignment trending with the Quality Services Unit manager. Data indicated a steady reduction in the number of mispositioning events over the past year until September 1996. Based on inspector observations and personnel interviews, the inspectors determined that a significant portion of the increased events since September 1996 resulted from a lower threshold for workers to report mispositioned components. However, poor work practices and operator error continued to account for several of the mispositioned components.

Components found out of NSA this period included:

- Both Unit 1 Waste Gas Decay Tank (WGDT) oxygen analyzers off
- 4KV circuit breaker ACB142A test switch 'B' in test
- 2-1 emergency diesel generator (EDG) governor cooler outlet valve (2EGS-19) shut
- 1-1 EDG instrument air dryer bypass valve (DA-169) open
- Three 120 VAC panel breakers open (AC-PNL-LW01 breaker 6, AC-PNL-SI02 breaker 10, AC-PNL-SI02 for TRS-CH-SI-03)
- Unit 2 Alternate service water system (SWS) strainer backwash valve (2SWE-245) throttled
- Unit 2 Alternate SWS pump strainer discharge valve (2SWE-1068) shut
- Unit 2 SWS local pressure gage (2SWS-PI105C and 101C) gage isolation valves throttled
- 2SWS-FI101A open
- Unit 1 river water system seal water filter inlet stop valve (RW-582) closed
- Unit 1 'C' component cooling water pump discharge valve (1CCR-9) open
- Unit 2 auxiliary building radiation monitor system grab sample isolation valve (RMP-RQ-300) open
- Unit 1 non-technical specification auxiliary feedwater (AFW) pump (FW-P-4, used as station blackout equipment) control switch off

Most components found out of NSA had little to no safety significance individually. Several were on portions of systems which were no longer in service, but had not been formally retired. However, several of the components were on safety related systems [Emergency Diesel Generator (EDG), Component Cooling Reactor (CCR), Service Water (SWS), Auxiliary Feedwater (AFW), and Waste Gas Decay Tank (WGDT) oxygen analyzers]. Operator error when positioning the WGDT oxygen analyzer power switches resulted in failure to monitor oxygen for explosive gases on November 30, 1996 as described in Section O4.1. Poor work practices caused the 2-1 EDG governor cooler outlet valve (2EGS-19) to be inadvertently shut which had the potential to adversely affect long term EDG operability as discussed in Section E2.3.

At least two recent component mispositionings represent repeat problems. 2EGS-19 and 20 are EDG governor cooler outlet valves on the two Unit 2 EDGs. One was found mispositioned on September 17, 1996, the other on January 28, 1997. The second repeat problem involved the Unit 1 oxygen analyzer power and pressure override switches which were misoperated due to a human factors issue (look-alike switches). Corrective action was previously taken, but it did not preclude recurrence.

On January 14, 1997 operators failed to shut the 'C' CCR pump discharge valve (1CCR-9) when securing the pump. The assistant NSS and the operator agreed to leave the valve open, contrary to procedures 1OM-15.4.H, "Securing A CCR pump or Placing the Spare CCR pump in Service," Rev. 1, and 1OM-15.3.B.1, "Valve List-1CCR," Rev. 7. This decision was made in anticipation that the 'B' CCR pump post-maintenance test would fail and the 'C' CCR pump would soon be returned to a standby lineup which would require the 1CCR-9 valve to be reopened. The operators failed to annotate this in the procedure and failed to update the control room valve position deviation log. The 'B' CCR pump successfully passed its post maintenance test and operators left 1CCR-9 in the incorrect position, contrary to procedure.

<u>Licensee Corrective Actions</u>

The inspectors expressed concern to licensee management that component mispositionings continued to occur despite previous corrective actions to address configuration control issues identified in 1995. Inspector follow-up of the 1-CCR9 mispositioning and RHS depressurization issues indicated recurring weaknesses in implementing station procedures. The licensee has initiated several corrective actions to (1) determine the extent of component mispositionings by walking down other systems and (2) raise the level of sensitivity to this issue through counseling and group briefing sessions. NRC management conducted two conference calls with licensee management to discuss the status of licensee event assessment and corrective actions. The inspectors observed several corrective actions in progress as listed below.

1) 1/2/97 Implementation of the Potential Tampering procedure was excellent as discussed in Section S1.1.
2) 1/28/97 Initiated weekly system lineups on all EDGs. Planned through at least 2/28/97 (No additional problems identified after 1/28 to date).
3) 1/28/97 Access to EDG rooms now requires NSS and security authorization (continues pending Plant Manager decision).
4) 1/28/97 Safeguards Operability Checklist system walkdowns performed on both Units. (No problems found.)
5) 1/28/97 Initiated emergency electrical supply system (4kV/480v/120v) lineups. (No problems found).
6) 1/30/97 Initiated system lineups for the 4 most risk significant PRA systems on each Unit. (approx 9000 components verified). Completed 2/04/97. (No problems found).
7) 1/30/97 Initiate instrumentation valve verification on the Unit 1 river water system and the Unit 2 service water system. This comprised approximately 300 instruments (over 1000 valves). Some valves

found out of position. Reasons for these were identified through licensee security investigations. No adverse impact on operability.

8) 2/03/97 QSU began doing a daily independent random valve verification on safety related systems. This is done by one person and continues as of 2/13/97. QSU is finding some process discrepancies such as the procedure-specified NSA position for a given valve being different in two different departments' procedures. QSU had previously been tracking mispositioning events and was in the process of doing an assessment when the issue grew larger in 1/97. Overall assessment responsibility was transferred to ISEG. But QSU has identified component mispositioning to be pursued as a top issue.

9) 2/03/97 Operations department assigned one additional person to perform independent random safety system walkdowns for 3-4 days. (No problems found).

10) 1/97 Operations department initiated a periodic audit of the NSA deviation log maintained in the Control Room. Problems were found in that Unit 2 control room staff was not consistently using the log to document components out of NSA as intended. Unit 1 Audit is in progress. Many systems not in use anymore have not been formally retired in place because no "Retire in Place" process exists at BVPS.

11) 2/06/97 Peer oversight was initiated for critical tasks as identified by the NSS or by the operators performing a task. The peer oversees operator self-checking and procedural use.

12) 2/07/97 In response to a radiation monitor grab sample isolation valve (RMP-RQ-300) found out of position, health physics personnel performed a 100% system lineup on all radiation monitor valves. (Over 900 valves were checked, no additional valves were found out of position.)

13) 2/08/97 The Company President, VP-Operations, Operations General Manager, and Security Manager performed a management assessment of the mispositioning issues. This review included detailed assessment of all events in the past 2 months for which the potential tampering procedure was entered. Findings were discussed with the NRC Resident Staff. Initial findings were meaningful and proposed immediate and long term corrective actions were developed.

14) 2/08/97 Ball valves (90 degree closure rotation with a straight actuator handle) were identified as a likely mispositioning group as they accounted for five of the recent mispositioning reports. Management initiated a project to visually sight every ball valve at the station (several thousand valves) and identify likely mispositioning candidates based on their location and proximity to other equipment or personnel passageways. Several ball valve handles were secured the previous week based on recommendations which followed previous mispositioning events.

15) 2/14/97 The ISEG mispositioned component/potential tampering aggregate assessment is scheduled to be complete in draft form.

16) 2/97 Senior managers stressed expectations for excellent configuration control, self checking, and procedure use at daily management

meetings, during shift turnover briefings, and at weekly operations department seminars.

17) 2/97 Several of the recent mispositioning reports were associated with equipment which had not been used in several years. Senior management determined that the station did not have a formal program to "retire equipment in-place." Management directed action to (1) temporarily identify system boundaries for equipment believed to be retired and (2) develop and implement a formal equipment retirement program.

The inspectors determined that licensee threshold for identifying components out of NSA is very low. Immediate corrective actions included individual position verification of over 9000 components. Of that group about 10 were found out of NSA, none of which was safety significant. Security and operations personnel have responded promptly and comprehensively to identified mispositioning events. Licensee corrective action during the December 1996 to February 1997 time frame has been substantial and very conservative. However, the inspectors remain concerned regarding improper operator use of procedures and poor work practices including system restoration following maintenance activities.

<u>Regulatory Concerns</u>
10 CFR 50, Appendix B, Criterion XVI states, in part, "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition." Inadequate control of plant component position, both safety related and nonsafety related, is a significant configuration control condition adverse to quality. Poor work practices and operator errors including failure to properly implement written procedures continued to result configuration control problems.

The inspectors determined that, as of February 8, 1997, licensee corrective actions have not been fully effective and have not precluded repetition of a significant configuration control condition adverse to quality. This is an apparent violation **(URI 50-334(412)/96010-01)**.

c. <u>Conclusions</u>

From September 1996 to February 1997, the licensee identified numerous components out of normal switch alignment (NSA) position. Although the licensee demonstrated a low threshold for identifying component misconfigurations and initiated several comprehensive corrective actions during this inspection period, the inspectors determined that previous corrective actions initiated to address similar problems in 1995 had been ineffective. Poor work practices and operator errors, including failure to properly implement written procedures, continued to result in configuration control problems. Failure to maintain adequate configuration control was an apparent violation.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdowns (71707)

The inspectors walked down accessible portions of selected systems to assess equipment operability, material condition, and housekeeping. Minor discrepancies were brought to DLC staff's attention and corrected. No substantive concerns were identified. The following systems were walked down:

- Unit 2 Recirculation Spray System
- Unit 2 Auxiliary Feedwater System
- Unit 2 Low Head Safety Injection System
- Unit 1 Charging System

O2.2 Control Room Deficiencies

a. Inspection Scope (71707)

The inspectors reviewed the type and number of control room deficiencies to assess whether appropriate action was being taken to maintain control room equipment, including annunciators and indicators, available to operators in good working condition. This review did not specifically include assessment of existing operator work arounds.

b. Observations and Findings

During control room tours from September to December 1996, the inspectors noted a large number of yellow caution tags on various control room equipment. Although the total number gradually decreased since September, a significant number remained. Control room deficiencies were mostly on indicators and annunciators. The inspectors discussed the various tags and equipment condition with operators. While none of the deficiencies individually had much safety significance, the inspectors observed that the total number (approximately 80 deficiencies between the two units), in the aggregate made operator activities more difficult to perform. Safety significant deficiencies were corrected promptly, but others tended to remain in backlog.

The inspectors noted one significant control room (CR) deficiency on December 23, 1996. Unit 2 nuclear instrument channel N41 received a positive rate trip signal when operators unlocked the gain potentiometer locking device. Operators routinely adjust the gain potentiometer to ensure the signal to the high power reactor trip circuitry remains conservative. A spurious N41 positive rate trip signal was also received the previous day during core flux mapping. This deficiency was of concern because it could cause an inadvertent reactor trip if it occurred while another channel was being tested. The inspectors discussed this deficiency with the control room staff and determined that operators were clearly briefed not to operate the gain potentiometer while another nuclear instrument channel was in test. Technicians completed corrective maintenance on the potentiometer on December 23 using maintenance work request (MWR) 59649. The shift supervisor signed the

MWR as complete on January 5, 1997, following a two week period of reliable performance. The inspectors determined that the timeliness for correcting this deficiency was appropriate.

The operations department had established a goal of $\leq$8 CR instruments and annunciators out of service (OOS) or caution tagged for a period of greater than 30 days per unit. The inspectors reviewed station monthly performance indicators and observed that the goal had been exceeded for most of 1996. The inspectors further questioned why only those deficiencies lasting greater than 30 days were tracked.

In December, an operations engineer was assigned to perform a detailed CR deficiency review and drive actions to get the deficiencies corrected in a more timely manner. In January, several of the longstanding control room deficiencies were corrected. The inspectors discussed the actions taken with the operations engineer. Prior to January, CR deficiencies had consistently been scheduled in the 12 week work schedule, but were often deferred when higher priority work arose and resources were limited. In addition, several deficiencies awaited post maintenance testing (PMT), which was not defined in the work package. Some deficiencies failed their PMT, but rework MWRs were not written. During this inspection period, the operations engineer closely coordinated between departments, facilitated work on several longstanding CR deficiencies, and made several recommendations to operations management to maintain higher visibility on this issue.

In January, the plant manager placed a higher priority on promptly correcting CR deficiencies. A dedicated instrumentation and controls crew was assigned to work CR deficiencies. CR deficiencies were listed in the daily plant status report for higher visibility and were discussed individually at the daily management meeting. Specific managers were assigned responsibility for action to correct each individual CR deficiency. The station goal was revised to $\leq$20 CR deficiencies per unit. The inspectors noted that this tracked all CR deficiencies, rather than only those outstanding for greater than 30 days. The plant manager also directed that CR deficiencies be scheduled for work within one to two weeks of identification to ensure they did not continue to get deferred in the 12 week planning schedule.

c. <u>Conclusions</u>

Non-safety significant CR deficiencies continued to accumulate in backlog during 1996, which in the aggregate, made operator duties more difficult to perform. Deficiencies were not actively managed and routinely exceeded the station goals. In December 1996 and January 1997 management placed a higher priority on promptly correcting CR deficiencies and clearly delineated responsibilities. The inspectors concluded that the actions taken and initial results were positive in reducing the number and duration of control room deficiencies.

O4 Operator Knowledge and Performance

O4.1 Deenergized Unit 1 Waste Gas Decay Tank (WGDT) Oxygen Analyzers

a. Inspection Scope (71707, 92901)

The WGDT oxygen analyzers are normally energized and are used to verify the potentially explosive gas mixture contained in the waste gas holdup system is maintained below flammable limits. On December 26, 1996, instrumentation and control technicians reported that both Unit 1 WGDT oxygen analyzers were deenergized, while operations personnel thought the analyzers were in service. The inspectors interviewed personnel and reviewed various station logs to assess licensee investigation of this event and to determine whether appropriate oxygen monitoring had been performed during recent WGDT operations.

b. Observations and Findings

After identifying that the WGDT oxygen analyzers were deenergized, both WGDTs were promptly sampled and certified to contain less than 1% by volume oxygen. This concentration was within the limits specified by Technical Specification 3.11.2.6. The analyzers were reenergized, and security personnel promptly initiated a potential tampering investigation and notified the inspectors as described in section S1.1. Immediate corrective actions were appropriate.

The inspectors questioned how long the oxygen analyzers had been out of service, the reason they were deenergized, and whether WGDT oxygen concentration had been properly verified during WGDT filling operation. Operations and security personnel each investigated this issue and determined that the WGDT oxygen analyzers were inadvertently deenergized on November 25, 1996. An operator inadvertently pulled out the power switches, which deenergized both oxygen analyzers, when he thought he was restoring the pressure override switch to the normal (pulled out) position. The analyzer power switch and the pressure override switch are similar in appearance and operation. The switches are located adjacent to each other on the analyzer control panel. Security personnel noted that poor housekeeping in front of the oxygen analyzer control panels further detracted from the operators ability to clearly focus on the correct control switch. Following discussion with operators and security personnel, the inspectors concluded that adverse human factors contributed to these switches being misoperated in the past.

The inspectors viewed the control panels, and reviewed the control room WGDT oxygen analyzer chart recorders, and previous problem reports associated with WGDT oxygen analyzer operation. The operations staff had previously placed yellow caution tags on the pressure switch override control switches to ensure the switch override was returned to the "pulled out" position when completed with alarm resets. In addition, permanent descriptive labels had recently been mounted on the panels to describe proper switch operation. Operations personnel had taken these corrective actions to address previous licensee identified difficulties operating the system. The inspectors noted that these efforts to correct past switch positioning errors were not fully effective.

Operations personnel determined that the WGDT compressor had been used on November 27 and 30, 1996 during corrective maintenance activities. There was no gas flow to the WGDT on November 27. However, there was gas flow to the WGDT on November 30 and the oxygen concentration was not properly monitored as required by TS 4.11.2.6.1. Operators incorrectly assumed that the WGDT oxygen analyzers and the control room recorder were operable and in service. This resulted from personnel error and operator log weaknesses.

Corrective actions included individual counseling on management expectations for self-checking, revising the Unit 1 and Unit 2 primary auxiliary building operator logs and the L5 surveillance verification logs to require periodic verification of oxygen analyzer operability, and assigning the associated licensee event report as required reading for all licensed operators and shift technical advisors. The inspectors determined that the log revisions were properly implemented. Corrective action effectiveness will be reviewed during follow-up inspection for this violation.

c. Conclusions

The Unit 1 WGDT oxygen analyzers were inadvertently deenergized on November 25 due to operator error and inadequate operator logs. Previous corrective actions to address improper operation of the WGDT power switch and pressure switch override control switch were ineffective. Failure to properly monitor oxygen concentration during WGDT filling operation is discussed along with additional configuration control issues in Section O1.7. Licensee investigation of this event was detailed and comprehensive.

O8 Miscellaneous Operations Issues (92901)

O8.1 Employee Concern Resolution Program

a. Inspection Scope (92901)

The inspectors reviewed Employee Concern Resolution (ECR) program procedures, interviewed the site ombudsman who implements the program, and discussed the general purpose of the program with various site personnel.

b. Observations and Findings

NRC inspection report 50-334(412)/96-04, dated June 6, 1996, reviewed the transition of the employee concerns resolution function from the Quality Concern Resolution Program to the ECR program. The report noted that, based on initial performance, the ECR program provided a satisfactory means to investigate and resolve employee concerns.

The inspectors reviewed the program's overall implementation since the transition period. The inspector observed that the ECR program posters and receipt forms continued to be readily available at a number of locations throughout the site. Based on discussions with a sampling of DLC employees, the inspectors determined

that personnel generally understood the program's purpose and knew how to submit a concern for resolution.

The ECR program was found to be implemented as specified in Nuclear Power Division Administrative Procedure 8.14, Employee Concern Resolution Program, Rev. 3. The inspector noted that the program continues to receive a few employee concerns each calendar quarter. The ombudsman has not identified any adverse trends in the number, type, or sources of the concerns.

c. Conclusions

The inspectors concluded that the Employee Concern Resolution program continues to be implemented as intended and provides an appropriate, confidential means to resolve employee concerns.

O8.2 (Closed) Licensee Event Report (LER) 50-412/96009: Missed Technical Specification (TS) Surveillance Test - Quadrant Power Tilt Ratio Calculation (QPTR).

a. Inspection Scope (92700, 92901)

On December 20, the Unit 2 Nuclear Shift Supervisor (NSS) determined that a TS required surveillance had not been performed within the specified time interval. The inspectors independently assessed the licensee's root cause assessment and corrective actions to preclude recurrence.

b. Observations and Findings

Early on December 20, 1996, operators successfully calculated the QPTR prior to exceeding 50 percent thermal power as required by step 141.a in procedure M-52.4A, "Increasing Power from 5% Reactor Power and Turbine on Turning Gear to Full Load Operation," revision 26. During the next shift the reactor operator observed that step 141.b, QPTR alarm check (2OST-2.4) was not signed off, and asked the assistant NSS if the QPTR surveillance had been completed. The assistant NSS reviewed the completed surveillance and responded that 2OST-2.4A (QPTR Manual Calculation) was completed satisfactorily. The reactor operator misunderstood this response and signed off step 141.b in procedure 2OM-52.4A. The NSS on the next shift could not locate the completed surveillance paperwork for the QPTR alarm check.

Since the QPTR alarm check had not been performed, the QPTR alarm was considered inoperable. TS 4.2.4 requires the QPTR calculation be performed within 12 hour intervals while the QPTR alarm is inoperable. The NSS promptly directed operators to perform a manual QPTR calculation and verified that the reactor's performance characteristics were within the TS prescribed limits. Over 16 hours expired between the QPTR calculations, which exceeded the time interval specified by TS. The inspectors reviewed this event with operators and verified that QPTR calculations were satisfactorily performed at the specified time intervals until the

QPTR alarm was returned to service. In addition, a core flux map performed on December 21 confirmed a normal flux distribution.

Operations personnel performed a root cause analysis (RCA) of this event to explore human performance as well as other contributing factors. The RCA identified two primary causal factors. The first factor was inadequate verbal communications, in that standard terminology and repeatbacks were not used between the reactor operator and the assistant NSS. The second factor was a weak procedure in that 2OM-52.4A did not specify a timeframe beyond 50% thermal power in which the QPTR alarm check must be successfully completed. Corrective actions included procedure changes to ensure that Unit 1 plant start up procedures properly specified when axial flux difference surveillances must be performed, counseling of individuals involved, and an event lessons learned summary developed for Operations Department required reading. The inspectors reviewed the proposed procedure and standards changes and determined that they were comprehensive.

c. Conclusions

Communications errors between operators and procedure weaknesses resulted in the failure to perform a TS required QPTR surveillance on December 20, 1996. The inspectors concluded that causal assessment and corrective actions were comprehensive and properly implemented. The LER accurately described the event in appropriate detail and met the reporting requirements of 10 CFR 50.73. This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy **(NCV 50-412/96010-02)**.

O8.3 (Closed) LER 50-334/96013: Failure to Perform Gaseous Waste Disposal System Oxygen Testing as Required by Technical Specifications.

The event and corrective actions were previously described in section O4.1. The LER documented the event in excellent detail, fully addressing the event, causal factors, and corrective actions. Corrective action effectiveness will be evaluated during inspector follow-up for the associated violation.

O8.4 General Comments (71707)

On January 15, 1997, during Unit 2 initial power escalation following a reactor trip, station management held power at 30% to evaluate a potential water hammer issue with the recirculation spray system. A plant with a design similar to Beaver Valley had recently identified the potential problem. Engineers performed an evaluation and short term compensatory measures were in place prior to commencing a load increase to full rated power. The long-term corrective actions were still being evaluated at the end of the period. The inspectors observed that management response to industry information regarding this issue was proactive and comprehensive. The management hold on reactor power was a conservative, safe decision.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Routine Maintenance Observations (62707)

The inspectors observed selected maintenance activities on important systems and components. The maintenance work request (MWR) activities observed and reviewed are listed below.

- MWR 059440 Repair MCC-1-E8, 480V Breaker Supply to FC-P-1B, the SFP

The activities observed and reviewed were performed safely and in accordance with proper procedures. Inspectors noted that an appropriate level of supervisory attention was given to the work depending on its priority and difficulty.

M1.2 Routine Surveillance Observations (61726)

The inspectors observed selected surveillance tests. Operational surveillance tests (OSTs), reviewed and observed by the inspectors are listed below.

- 1OST-30.3 "Reactor Plant River Water 1B Test"
- 1OST-36.2, "Diesel Generator No. 2 Monthly Test"
- 1OST-30.1A "[1WR-P-9A] Auxiliary River Water Pump Test"

The surveillance testing was performed safely and in accordance with proper procedures. Additional observations regarding surveillance testing are discussed in the following sections. The inspectors noted that an appropriate level of supervisory attention was given to the testing, depending on its sensitivity.

During the performance of 1OST-30.1A, operators noted that acceptance criteria for pump delta P (change in pressure across the pump from suction to discharge) was missing from the OST. A note stated that, "Acceptance criteria is not available for this test performance. It shall be determined prior to next performance. Therefore, for this performance, delta P measurements are for information only." The note was also in 1OST-30.1B for the other auxiliary river water pump. Operators discussed the lack of acceptance criteria with the system engineer, who documented it in Condition Report 970193. The missing criteria was used for balance of plant trending only. Additional criteria to meet technical specification requirements was in the OST, and the pump performed satisfactorily. Inspectors assessed that operators displayed a good questioning attitude in following up the note.

The inspectors discussed the issue with the system engineer and reviewed Engineering Memorandum (EM) 113834. The EM requested that a minimum operating point be developed for the auxiliary river water pumps to help judge pump performance for purposes of the Maintenance Rule and probabilistic risk

assessment. The EM due date was before the next scheduled performance of the OST. The criteria is not required for technical specifications (TS) or ASME testing. Inspectors assessed that the development of performance criteria in addition to the minimum required by the TS was a good initiative by the system engineer.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Cold Weather Equipment Problems

a. Inspection Scope (62707)

During the winter months, Units 1 and 2 have experienced numerous heat trace and freezing of lines and instruments. The inspectors reviewed the significance of the freeze protection problems and their impact on operation of the plants. The inspectors also discussed with system engineers the current plans and corrective actions to address the multiple cold weather issues.

b. Observations and Findings

Over the past 2 months, Units 1 and 2 had cold weather related problems with numerous systems. Many failures were the result of heat trace or insulation not properly installed or failing to provide adequate freeze protection. Although almost all problems were associated with non-safety systems, the failures resulted in an increased burden on the operations staff to identify and compensate for the equipment not functioning as designed. In NRC Inspection Report No. 50-334(412)/96-08, the inspectors identified that a large number of work requests on heat trace were outstanding, and that the non-safety related heat trace circuits were not periodically calibrated. The licensee's quality assurance organization also identified that an excessive number of work requests were not completed prior to the onset of winter. Although the inspector could not determine at the close of this period whether these two issues directly contributed to the failures, they highlighted the lack of a focal point for freeze protection which did contribute to the many failures.

The inspectors noted three lines associated with the refueling water storage tank (RWST) were adversely affected by the heat trace problems, although only one was considered safety related. On Unit 1, the operators received repeated control room alarms for low temperatures on the NaOH chemical addition line. After each alarm, the operators would run the chemical addition pump (QS-P-3) to clear the alarm. Although no line freeze up occurred, this resulted in increased burden on the operations staff and increase wear on the chemical addition pump. Also on Unit 1, the makeup line to the RWST froze due to a heat trace failure and breaker trip. Although considered a non-safety line, this condition presented an operational challenge to refilling the RWST and the line is used in the Emergency Operating Procedures (EOP). On Unit 2, a RWST level transmitter froze due to an insulation gap. This level instrument is the narrow range RWST level instrument and has no safety function, but is a control room instrument.

The inspectors reviewed the UFSAR and noted that for Unit 1 all "vital lines, such as those which contain boric acid solution which may not be in heated areas, are traced by two circuits." The inspectors reviewed with system engineers to determine if the preceding RWST lines met the UFSAR requirements. Based on extensive discussions with design and system engineers and review of additional material, the inspectors were not able to ascertain the licensee specific definition of vital lines and whether those lines met UFSAR 8.5.2.8. The above RWST lines do not have redundant heat trace as described in the UFSAR. This item remains unresolved pending determination of the exact determination of the term "vital lines" and their relation to the above components and determination of whether the chemical addition line meets the above criteria with respect to the potential to freeze. Determination on whether the licensee meets UFSAR 8.5.2.8 descriptions with respect to heat tracing of Unit 1 vital lines is unresolved **(URI 50-334/96010-03)**.

The licensee has addressed most of the immediate freeze protection problems. Initially, they built several temporary enclosures to prevent further freezing of lines. The majority of problems are being addressed with more permanent corrective actions. Currently they are determining longer term corrective actions through a cold weather protection program review. The inspector observed increased management involvement in addressing the program deficiencies.

c. Conclusions

Beaver Valley Unit 1 and Unit 2 experienced numerous freeze protection problems this winter. Although safety related equipment problems were minimal, the failures resulted in an increased burden on the operations staff. The licensee failed to adequately address the problems identified in their safety audit and in a previous NRC inspection report. Corrective actions, although not fully implemented, appear to address the current problems.

M2.2 Unit 2 Reactor Trip, Secondary System Performance

a. Inspection Scope (92902)

On January 6, 1997, Unit 2 experienced a reactor trip. Prior to and after the reactor trip several secondary problems occurred. The inspector discussed with system engineers and Event Review Team (ERT) members the associated problems, and conducted plant walkdowns to assess the secondary systems failures on plant safety.

b. Observations and Findings

Approximately 4 hours prior to the reactor trip, Unit 2 began to experience problems with moisture separator reheater (MSR) control valves closing. Eventually all four MSR control valves closed. This resulted in the loss of extraction steam to the second point feedwater heaters. The transient caused the 'A' heater drain and separator drain pumps to trip on low level in the 'A' heater drain tank. 'B' heater drain tank was observed to be controlling normally. The 'A' pumps were restarted,

but normal flow was not reestablished. The condensate pumps were providing additional flow to compensate. The feedwater pumps' suction pressure was reduced in this condition, and an increase in flow velocity is also observed. Approximately 2 hours after the system was stabilized, the reactor tripped due to a main transformer ground relay. The closing of the main feedwater regulator valves and increased flow velocity resulted in increased pressure seen on the secondary side. Six condensate and feedwater relief valves lifted and failed to reseat.

The ERT determined that a loose wire connection for a low pressure turbine inlet steam temperature thermocouple resulted in the MSR control valves closing. This thermocouple was worked this past outage and is considered a workmanship problem. The immediate corrective action was to place the reheater control system in manual control during steady state operation. Other workmanship items were identified involving governor valve position indication problems evident following the last refueling outage and relief valve repair rework required during the January 1997 forced outage. Long-term corrective actions are to evaluate a modification to the reheat control system and enhancements in work practices during major turbine overhauls and inspections. Heater drain system valves, piping, and control systems were extensively tested and evaluated. The relief valves stuck open due to various debris, and for two of the relief valves, the disc stuck in the guide. The relief valves were repaired and placed back in service. System engineering are completing a review of Beaver Valley relief valves performance versus the industry performance. The inspectors observed that corrective actions were appropriate and noted that long term actions to reduce the pressure transient were excellent initiatives.

In addition to the specific corrective action noted above, additional hold points were added during startup and power ascension for data collection and analysis by the system engineers on the MSRs and heater drain system. This action ensured that the secondary system problems were addressed and allowed for further improvement on the control systems. The inspectors concluded that the data gathering was well thought out and was relatively non-intrusive to operations.

c. Conclusions

Prior to the reactor trip, BVPS2 experienced a secondary system transient as a result of lack of quality workmanship. The transient and additional secondary system problems did not impact the ability of operators to place Unit 2 in a safe shutdown condition after the reactor trip. The corrective actions to address the failures were appropriate.

M8 Miscellaneous Maintenance Issues (9 902)

M8.1 (Closed) Unresolved Item 50-334(412)/96009-01: Proper verification of qualified suppliers list (QSL) prior to using vendor services for safety related work.

In December 1996, the inspectors determined that station procedures may not properly assign responsibility for QSL certification prior to using a vendors services for safety related work. Annual vendor audits by the quality assurance department may result in restrictions and conditions being established which must be satisfied

prior to using a vendor. These conditions are added to the QSL. However, it appeared that if a blanket purchase order (PO) had been previously issued for the vendor's service, station personnel did not recertify the vendor against the updated QSL requirements. The inspectors questioned whether the licensee properly certified the vendor for two safety related leak injection repairs performed on December 1-2, 1996.

During this inspection period, the licensee reviewed the inspectors' concern and determined that the vendor was not properly certified for safety related work performed on December 1-2, 1996. In addition, station procedures did not address recertification against the current QSL for vendors whose services were covered under blanket POs. Several departments incorrectly believed that some other department was performing this function.

10 CFR 50, Appendix B, Criterion II, Quality Assurance Program, requires in part that the QA program shall provide control over activities affecting the quality of systems, structures, and components consistent with their importance to safety. Additionally, the program shall take into account the need for special skills to attain the required quality. The program shall be documented by written policies, procedures, or instructions and shall be carried out throughout plant life. Contrary to the above, station procedures were inadequate to assure vendors met QSL requirements prior to performing safety related work. As a result, a vendor performed safety related leak injection repair services on December 1-2, 1996 without satisfying applicable quality requirements. This is a violation **(VIO 50-334(412)/96010-04).**

The inspectors met with QA and procurement personnel to discuss corrective actions for this condition. Procurement specialists reviewed all outstanding blanket POs for safety related services or materials and cross checked this with the current QSL. Change orders were then issued for 22 safety related blanket POs to address current QSL conditions which had changed since the blanket POs were initially issued. The licensee reviewed all services and materials provided under those 22 original POs and determined that there were no resulting adverse safety consequences.

Effective January 1997, procurement specialists have been assigned the responsibility to verify QSL conditions are incorporated into the PO to a vendor. If a QSL change occurs affecting a vendor with an outstanding safety related PO, procurement specialists immediately issue a change order to the associated PO which incorporates the new QSL condition which must be satisfied by the vendor. Procedure revisions to incorporate this practice were under development at the end of the inspection period. As an interim measure, a vendor service coordinator has also been assigned to verify QSL conditions are met prior to bringing a vendor on-site to perform work. The inspectors determined that the corrective actions initiated were appropriate. Final implementation of the revised procedures remains subject to inspector follow-up for this violation.

III. En ineering

E1 Conduct of Engineering

E1.1 Unit 2 Reactor Trip, Mair Transformer Protection Relay Actuation

a. Inspection Scope (71707, 92903)

Beaver Valley Unit 2 experienced a reactor trip on January 6 due to an actuation of a main transformer backfeed ground protection relay. The inspectors conducted reviews of the root cause analysis, testing of the failed and associated relays, and corrective actions.

b. Observations and Findings

On January 6, 1997, at 5:56 a.m., Unit 2 experienced a reactor trip from 98% power. Immediately preceding the reactor trip, a main transformer ground alarm was received indicating that a main transformer ground protection relay (59-202G) actuated, thus causing the turbine trip and reactor trip. Review of alarm response revealed that no other main generator or main transformer protective relay actuation occurred during the event. The licensee assigned the Event Review Team (ERT) to determine the root cause of the reactor trip and provide corrective actions.

The licensee performed testing on the 59-202G and four other relays in the protection system for the main generator and main transformer. All relays performed as expected and within their tolerance bands. Relay engineers determined that if a ground on the system was present, a different alarm relay (259-1201) would precede the 59-202G relay actuation. The testing also revealed that the 59-202G relay actuated near the lower end of its tolerance band. The licensee also conducted tests on the main transformer oil for indications of degradation expected from a fault. The oil was found to be satisfactory. Based on the review, testing, and inspections of the equipment associated with a generator ground, the licensee concluded that no actual ground occurred. The inspectors noted that a lack of installed instrumentation hampered the investigation and prevented engineers from determining an exact cause of the relay actuation prior to returning the plant to power.

The licensee reviewed the purpose of the 59-202G. The original design setting sheet identified that the relay was designed only for the main transformer backfeed ground protection. Operations procedures and the elementary electrical diagram had the relay "cut in" for both power and backfeed operations. Relay engineering showed that the relay may be more susceptible to normal zero sequence voltage swings when operated during normal power operations. The relay was in this configuration since original plant startup. Unit 1 had a similar relay, but the relay was placed in operation only during backfeed through the main transformer. The licensee determined that inadequate implementation of the design of relay 59-202G was the root cause of the reactor trip.

The inspectors found the root cause evaluation to be thorough with the limited amount of information available. All possible scenarios were reviewed and extensive testing provided valuable information to determine if an actual fault existed. Licensee corrective actions to address the root cause included:

- Ensuring 59-202G relay be in service for main transformer backfeed operations, procedures and checklists were revised.
- Monitoring selected parameters and relays during field flashing of the main generator and the power ascension to confirm that no ground existed and to gain additional information about the reactor trip.
- Perform reviews of relay setting sheets to ensure that they are consistent with controlled drawings and procedures.

The above corrective actions were completed, however the review of relay setting sheets was only of the main transformer and station service transformer relays. A more comprehensive review is ongoing.

Monitoring during the startup identified contributing causes. The monitoring identified that the zero voltage readings across the 59-202G relay were high, and with vibration induced wear on the main transformer secondary wiring resulted in the relay actuation.

c. Conclusions

The licensee evaluation of the reactor trip was of sufficient depth to accurately determine the root cause (inadequate original design implementation). Although the relay is not described in the UFSAR and is not a safety related Appendix B criteria component, the failure to adequately implement the original design is a noted weakness. Corrective actions generally addressed this weakness.

E2 Engineering Support of Facilities and Equipment

E2.1 Unit 2 Recirculation Spray Pump External Flood Barrier Not Installed

a. Inspection Scope (37551, 92903)

On January 11, 1997, engineers determined that several recirculation spray (RS) pump flood protection seals were not installed or were degraded. The flood seals were designed to protect equipment in the safeguards building from the effects of the design probable maximum flood (PMF) to 730 foot elevation. Operators cooled down the reactor plant from mode 3 to mode 5 and the flood seals were installed/repaired. The inspectors reviewed design drawings, maintenance work packages, and interviewed personnel to assess licensee response to this event.

b. Observations and Findings

Initial Identification

The inspectors interviewed various engineers to determine how the missing flood seals were identified and why they were missing. In early January 1997 operators received a RS valve pit sump high water level (12 inches) alarm. Engineers inspected the valve pit areas for potential water intrusion sources including RS system valve leakage, groundwater watertight membrane degradation, or degraded shakespace water stops. No visible sign of active water inleakage was evident. A previous waterstop splice repair appeared intact. Engineers next went up to the 718 foot elevation level in the RS pump cubicles to search for a evidence of a potential water drainage path from above. On January 8, an engineer observed that the RS pump flange plates were not properly bolted into place.

Engineers reviewed construction drawings and past design documentation to determine whether the existing configuration satisfied design requirements. Engineers determined that each of the four RS pumps was missing its external penetration flood protection seal which was to be installed between the 42 inch pipe sleeve and the concrete flooring at the 718 foot elevation. The flange plate was to bolt down on top of the seal. In addition, the internal flood protection seal between the 24 inch pump casing and the pipe sleeve was degraded on three of the four pumps. The inspectors walked down the RS pump cubicals and noted that the missing flood seals was not visually obvious. A solid grey material connected the concrete floor to the RS pump pipe sleeve with no visible air gap. Discussions with engineers revealed that this solid material was rotofoam, a slightly compressible non-watertight material which was installed to permit some lateral movement.

The Updated Final Safety Analysis Report (UFSAR) was recently digitalized to provide computer word search capability. Licensing engineers used this feature to aide in identifying flood protection design requirements. Licensing engineers using the newly developed UFSAR word search capability, determined that the RS pump flood seals were not installed as described in UFSAR sections 2.4.1.1 and 3.4.1. The inspectors determined that the persistence in investigating potential sources of water inleakage and the new UFSAR word search capability were instrumental in identifying the flood seal deficiency.

Causal Analysis and Corrective Actions

Upon determining that the flood seals were not properly installed, corrective MWRs were promptly initiated. In parallel, a RS pump operability determination was performed. The pertinent question was whether the RS pumps could perform their design accident mitigation function reliably without the flood seals installed. Licensing, operations, and engineering department personnel worked together on this assessment. The design basis for the RS system is to operate in the post loss of coolant accident environment to maintain the containment subatmospheric for a 30 day period. If a PMF were to occur during the 30 day period without the flood seals properly installed, the RS system may fail to function. Specifically, the RS suction valves may become submerged which could cause them to inadvertently shut. The inspectors determined that the licensee had properly evaluated the RS system operability issue. The Operations department developed a detailed

discussion paper regarding the January 11, 1997 Unit 2 RS system operability determination. This was an excellent teaching tool developed to enhance operators skills regarding operability determinations.

On January 11, the operators declared both RS trains inoperable and placed the plant in mode 5 in accordance with TS 3.0.3. Seal repairs were promptly initiated and completed on January 13. The inspectors reviewed the work packages with engineers and visually inspected the repair workmanship. Engineers demonstrated a detailed knowledge level regarding RS flood seals and the repairs were of good quality.

The licensee identified the cause of the missing/degraded RS flood seals to be incomplete construction contractor documentation and lack of overall knowledge of flood protection by the RS flood seal installation crew. The quality services department conducted over 200 additional flood seal and fire seal inspections to determine the extent of the missing seal problem. No other damaged or missing seals were identified. The inspectors discussed this sample inspection and the results with engineering personnel and determined that the scope of this review was appropriate. In addition, engineers identified additional enhancements to the flood seal inspection program which are intended to be implemented on both units. The inspectors determined that corrective actions were appropriate and completed in a timely manner following issue identification.

Reportability
The licensee properly reported this event as required by 10 CFR 50.72 and 10 CFR 50.73. Based on initial discussions regarding the licensee's ongoing 100% UFSAR review initiative, the inspectors determined that the missing RS pump flood seals would most likely have been identified during the UFSAR reviews. Therefore, consistent with Section VII.B.3 of the NRC Enforcement Policy, this issue is not subject to enforcement action.

c. Conclusions

Incomplete documentation and lack of overall knowledge of flood protection by the original construction recirculation spray (RS) flood seal installation crew resulted in missing and defective Unit 2 RS pump flood seals. On January 11, both RS trains were declared inoperable and mode 5 was entered as required by technical specifications. The basis for the operability determination was technically sound. The inspectors determined that engineer persistence in investigating potential sources of water inleakage and the new UFSAR word search capability were instrumental in identifying the flood seal deficiency. Engineers demonstrated a detailed knowledge level regarding RS flood seals. The inspectors determined that the flood seal repairs were of good quality.

E2.2 High Temperature on RCP B Stator

a. Inspection Scope (37551)

Inspectors reviewed Unit 1 Temporary Modification (TM) 1-97-01 and its associated 10 CFR 50.59 evaluation. The modification was to remove two of the four motor stator inspection covers on reactor coolant pump (RCP) RC-P-1B to bypass the motor air coolers, which were coated with boric acid, which reduced their heat transfer capability.

b. Findings and Observations

During review of 1OST-36.14, "Temperature Trending of Large Motors," engineers noted RCP B stator temperature was elevated above the other two RCP motor stators. Trending data showed that the temperature had risen from 217 degrees F on December 23, 1996, to 252 degrees F on January 13. Temperature had been approximately 185 degrees in the November timeframe. Over the same period of time, RCP A stator and RCP C stator had been steady at about 212 degrees and 206 degrees, respectively. The stator temperature limit recommended by the vender is 311 degrees.

System engineering staff found what appeared to be a very light coating of boric acid on one of the two motor air coolers. The source of the boric acid could not be determined, however. After consultation with the vender, the TM was prepared and the inspection covers were removed. Stator temperature lowered to about 204 degrees and remained steady through the remainder of the inspection period.

Inspectors discussed the issue with system engineering staff and operators and reviewed the TM. The evaluation thoroughly covered the safety impact of the modification using sound engineering judgement. The stator temperature was being monitored daily by the system engineer. Unless further degradation is detected, DLC intends to investigate further and resolve the issue during the refueling outage scheduled later this year.

c. Conclusions

Inspectors assessed that the elevated temperature on RCP B stator had been satisfactorily identified and addressed by system engineering staff. The TM was properly evaluated, reviewed, approved, and implemented by DLC, and provided assurance that the RCP would perform its intended safety function. DLC intends to resolve the issue during the next refueling outage.

E2.3 Emergency Diesel Generator (EDG) 2-1 Operability Assessment

a. Inspection Scope (37551, 92903)

On January 28, 1997, an operator observed that the EDG 2-1 governor cooling water outlet valve (2EGS-19) was 95% shut instead of its normal full open position. Security initiated a potential tampering event investigation which is discussed in

Section S1.1. Engineers performed an operability evaluation to evaluate the effect of the mispositioned valve. The inspectors reviewed the vendor manual and test records, and assessed the operability determination.

b. Observations and Findings

The EDG governor oil heat exchanger functions to maintain governor control oil within a limited temperature band to assure control oil maintains an appropriate viscosity to support stable governor speed control. Internal governor adjustments of various needle valves are established based on the known oil viscosity. The inspectors reviewed the vendor manual for the Woodward Model EGB-50C governor actuator and noted that the specified normal operating oil viscosity band was 100-300 saybolt universal seconds (SUS). An expanded viscosity band of 50-3000 SUS is permitted for limited operation outside of the normal operating oil temperature band. The vendor manual further states that the EDG is least stable when running at no load. Conversely, the inspectors determined that the EDG is inherently most stable when parallelled to the off-site power grid as is done during the monthly surveillance run. When supplying the emergency bus loads, the EDG would be more stable than when unloaded, but less stable than when synchronized to off-site power. The inspectors questioned whether the EDG was operable and capable of performing its design accident mitigation function with 2EGS-19 in the 95% shut position.

On January 28, 1997, operators reopened 2EGS-19 and successfully performed the monthly EDG operability surveillance test the following day. No speed instability was identified during the surveillance including when the EDG was running unloaded at normal speed. Engineers determined that the valve operating handle had most likely been bumped, and thereby mispositioned, during painting activities in November 1996. Monthly surveillance tests were successfully completed in December 1996 and January 1997. However, a slight speed control fluctuation (+/- 0.1 hertz) was identified after the EDG was unloaded during both surveillance tests. At the time engineers did not consider the slight speed oscillation to be significant since it remained within the allowable range for normal operation. Based on the successful surveillance tests, engineers determined that the EDG was operable, had remained operable during the time that 2EGS-19 was shut, and that the EDG governor was not damaged. In addition, engineers believed that the EDG would have been capable of performing its design seven day accident mitigation function if called upon with 2EGS-19 in the as found position.

The inspectors questioned the basis for the licensee operability determination. Although the EDG had passed the monthly surveillance tests at load for one hour, several concerns had not been addressed. The maximum expected governor oil temperature and viscosity for a one hour and a seven day loaded run under design accident conditions had not been evaluated. Initial discussions with the system engineer indicated that based on industry testing, an EDG governor failure due to high control oil temperature would occur rapidly. This failure would not be gradual and therefore would not provide time for operators to diagnose and correct the problem once it began. The EDG governor oil had not been sampled. Engineers had not documented the assumptions used in their operability determination.

Following discussions with the inspectors, the EDG 2-1 governor oil was sampled and engineers developed a documented operability evaluation. The inspectors agreed with the licensee determination that the EDG governor had not been damaged and that the EDG was currently operable, with the 2EGS-19 valve open. However the inspectors noted that the documented operability evaluation was very qualitative in nature and lacked specific details, facts, and calculations to fully support several of the statement and conclusions contained in the evaluation. Upon discussion with licensing engineers, the inspectors were informed that the operability evaluation lacked sufficient analysis to support the EDG operability determination necessary to assess whether the 2EGS-19 mispositioning was a reportable event. At the close of the inspection period the licensee reopened the EDG 2-1 operability evaluation for further analysis. The issue of EDG operability with 2EGS-19 mispositioned remains unresolved **(URI 50-412/96010-05)**.

c. Conclusions

On January 28, 1997, operators found the EDG 2-1 governor cooling water outlet valve (2EGS-19) 95% shut instead of full open. The valve was promptly repositioned and the EDG was successfully tested to verify operability. The inspectors questioned whether the EDG had been capable of performing its design accident mitigation function with 2EGS-19 in the 95% shut position. The inspectors determined that the initial engineering evaluation did not contain sufficient detail to resolve the issue. The licensee reopened the engineering evaluation for further analysis. Long term operability remains an unresolved issue.

E8 Miscellaneous Engineering Issues

E8.1 Criticality Monitors

a. Inspection Scope (92903)

10 CFR 70.24 requires, in part, that a criticality alarm system shall be installed for detection of criticality during the storage of fuel assemblies. In August 1996 the inspectors conducted an information gathering survey to determine whether BVPS Unit Nos. 1 and 2 had such alarm systems installed.

b. Observations and Findings

The inspectors determined that neither BVPS unit had the required criticality alarm systems installed. However, BVPS-2 had been granted an exemption from the criticality alarm requirements of 10 CFR 70.24 in Special Nuclear Material License No. SNM-1954 on April 9, 1986, and this exemption had been included in Facility Operating License NPF-73 when it was issued to the licensee on August 14, 1987. Therefore, a criticality alarm system is not required for BVPS-2.

The inspectors also determined that the licensee was exempted from the criticality alarm requirements of 10 CFR 70.24 by Special Nuclear Material License SNM-1472 issued for the initial receipt and storage of BVPS-1 fuel. This license and exemption expired when the BVPS-1 construction permit was converted to Facility Operating

License DPR-66. However, due to an apparent oversight, this exemption was not requested for inclusion in Facility Operating License DPR-66, issued in 1976. In December 1996, the licensee submitted an exemption request from the requirements of 10 CFR 70.24 for Unit 1 which is under evaluation.

c. Conclusions

Failure to have the required criticality alarm system installed to monitor the Unit 1 new fuel storage area, or to have a valid exemption from the criticality alarm requirements of 10 CFR 70.24, is a violation **(VIO 50-334/96010-06)**.

E8.2 Steam Generator Water Level Control System and Protection System Interaction

a. Inspection Scope (92903)

The inspectors reviewed the corrective actions of LER 96-06, "Potential Control and Protection System Interaction in Steam Generator Water Level Control." The inspectors further evaluated the following procedures to ensure that the revisions appropriately applied the requirements of IEEE-279:

- 2 OM-24.4.ABK Annunciator Response to *Main Steam Flow Channel Selected Trouble*
- 2 OM-24.4.IF Instrument Failure Procedure
- 2 MSP 24.26-I (24.29-I) (24.31-I) Loop 1 (Loop 2) (Loop 3) Feedwater Flow Channel IV Calibration
- 2 MSP 21.07-I (21.08-I) (21.09-I) Loop A (Loop B) (Loop C) Steamline Pressure Protection Channel IV Test

b. Observations and Findings

On October 24, 1996, engineers identified that BVPS2 had a potential for a condition outside of their design basis. The immediate concerns and corrective actions were addressed in NRC Inspection Report No.50-334(412)/96-08. The condition outside the design basis was a control and protection channel interaction between main steam flow and steam generator level channels, which did not meet IEEE-279 standard. Based on IEEE-279, a second failure must be postulated under those conditions. The immediate corrective actions by the licensee was to select the steam flow transmitter that did not have the control/protection interaction with the steam generator level channel. The immediate corrective actions also addressed the possibility of a failure of the steam flow transmitter. If the steam transmitter (with the control/protection interaction) is selected in response to a failure, the operators will receive a control room annunciator and would declare the corresponding steam generator (SG) level transmitter inoperable,thus entering the Technical Specification. The inspectors raised further concerns whether the IEEE-279 standards would be met during calibration or tests of the other channels. Discussions with procedural writers and review of the procedures revealed a sound method of ensuring IEEE-279 standard were met. The immediate and intermediate corrective actions were effective in maintaining the design basis. The inspector

independently verified that all aspects of IEEE-279 were applied in the calibration procedures. Long-term corrective actions were still being pursued by the licensee.

c. Conclusion

The inspector found the corrective actions in response to LER 90-06 to be extensive to ensure compliance with IEEE-279. Engineers and procedure writers effectively addressed all immediate concerns associated with the control and protection system interaction during calibrations of the affected channels.

IV. Plant Support

R3 RP&C Procedures and Documentation

R3.1 Review of Chemistry Sampling and Analysis Procedures

a. Inspection Scope (71750)

The inspector reviewed selected aspects of the chemistry sampling program, including general procedure adequacy, chemistry sampling and analysis techniques, and supervisory oversight.

b. Observations and Findings

The inspector observed a chemistry specialist performing both primary and secondary plant chemistry samples. The chemistry specialist demonstrated a high level of knowledge of sampling procedures. The inspector noted that the specialist did not refer to procedures during the sampling process, which was consistent with chemistry department expectations for routinely performed samples. Analysts are expected to be thoroughly familiar with routine sampling procedures, and step-by-step referral to procedures is not required for routine samples.

The inspector also observed a portion of a chemical analysis of a sample for boron concentration. The procedural steps were performed as specified in the appropriate chapter of the Beaver Valley 1/2 Chemistry Manual. A current version of the Chemistry Manual was readily available for use in the laboratory as needed by the analysts. The procedures reviewed by the inspector were detailed, with applicable references.

During discussions with a chemistry specialist and the chemistry manager, the inspector learned that chemistry procedures are reviewed for technical adequacy on a routine basis. A number of procedures were upgraded within the past year. Also, the inspector found that for infrequent or one-time samples, a sample procedure may not be available. However, procedural guidance in the Chemistry Manual allows for these types of samples to be taken with concurrence of the operations nuclear shift supervisor.

The inspector determined that the chemistry department has a formal process for supervisors and senior chemists to observe the performance of chemistry specialists/analysts. This surveillance process documents, through the use of checklists, the observations of various samples and analyses. The checklists specify that the observer review a number of attributes, including procedure adherence, techniques, and general knowledge. The inspector reviewed several completed checklists for the last several months and considered them adequate for their intended purpose.

c. Conclusions

The inspector concluded that chemistry samples and analyses are generally performed in accordance with approved procedures. Chemistry department procedures were found to be adequate, and upgrades to the procedures were noted to be accomplished as needed. The department uses a documented supervisory oversight process to review the performance of chemists with regard to procedure adherence, laboratory techniques, and other attributes.

L1 Review of FSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compared plant practices, procedures and/or parameters to the UFSAR description.

While performing the inspections discussed in this report, the inspectors reviewed the applicable parts of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters with the exception of the Unit 2 RS pump external and internal flood barriers as described in Section E1.1; and the Unit 1 RWST heat trace circuits as described in Section M2.1.

S1 Conduct of Security and Safeguards Activities

S1.1 Security Response to Misaligned Components

a. Inspection Scope (71750, 92904)

Several valves and switches were found out of their normal alignment during this inspection period. Security responded and treated several of these reported component mispositioning events as potential tampering events. The inspectors reviewed operations, security, and management response to each event to assess station procedures and sensitivity to potential tampering issues.

b. Observations and Findings

From December 26, 1996, to February 7, 1997, several valves and switches were found out of their normal switch alignment (NSA) position. Station personnel have developed a very low threshold for identifying components out of NSA and treating

them as potential tampering events until reasonably proven otherwise. Components found out of their NSA were promptly reported to the control room shift supervisor (SS). The SS promptly notified security personnel for consideration of potential tampering actions, with one isolated exception. On January 24, 1997, a 4kV breaker overcurrent protection test switch was found out of NSA, but the SS did not notify security until 3 hours later, while operations personnel evaluated component operability. Management reiterated the importance of notifying security promptly, and no repeated delays occurred. The inspectors determined this corrective action was effective.

The inspectors reviewed security investigations and interim compensatory measures for several of the potential tampering events. The security compensatory measures and investigations were timely and thorough. The inspectors determined that Security Procedure 16.16, "Response to Indications of Potential Tampering, Arson, Vandalism, or Malicious Mischief," Rev. 0, was comprehensive and was effectively implemented. Security did not find any indication of malice or intentional tampering. The mispositioning typically did not adversely effect system operability and most of the affected components were unlikely tampering targets. Station management and the Independent Safety Evaluation Group were performing broad based reviews of the mispositioning events to assess trends and potential for tampering at the close of this inspection period. Interim corrective actions are discussed in Section O1.7.

Security personnel revised the senior reactor operator Security Topic requalification training plan to incorporate additional insights regarding potential tampering events. The inspectors reviewed the training plan including the discussion of Security Procedure 16.16 and found it to be comprehensive.

c. Conclusions

The inspectors determined that station personnel demonstrated a very low threshold for identifying components out of NSA and treating them as potential tampering events until reasonably proven otherwise. Security compensatory measures and investigations were timely and thorough. Communications between operations, security, and NRC personnel were timely. Potential tampering procedures were comprehensive, and no indication of tampering was identified. Operator requalification training plan revisions to incorporate additional insight on potential tampering issues were excellent.

S1.2 Security Response to Degraded Protected Area Barrier

a. Inspection Scope (71750, 92904)

A ruptured fire main degraded the protected area security perimeter and reduced fire fighting capabilities on-site. The inspectors reviewed security response to this event and compensatory measures established to maintain appropriate control regarding assess to the protected area.

b. Observations and Findings

On January 24, 1997, the fire main ruptured underground causing a water stream to shoot upward from beneath the ground near the protected area perimeter. Intrusion detection alarms were received and security personnel responded promptly. No intruders were observed, however, the erosion from the water stream degraded the sloping ground embankment along one side of the security perimeter. An armed guard was immediately stationed as a compensatory measure.

A portion of the pressurized fire water header was isolated to stop the leak. Additional fire protection equipment was prepositioned to provided coverage for the area at which the fire main was isolated. The inspectors discussed the additional fire protection measures with the station fire protection engineer and determined they were appropriate.

Repairs involved a significant amount of excavation in the vicinity of the protected area fence. A secondary protected area fence was erected and the armed guard was maintained stationed throughout the end of this inspection period. The inspectors discussed the compensatory measures with the security manager and determined they were appropriate. The inspectors frequently toured the degraded perimeter area during backshift hours and interviewed security personnel. The guards were alert and clearly understood their responsibilities.

c. Conclusions

Security response to the ruptured fire main and degraded security perimeter were excellent. Security and fire protection compensatory measures were appropriately maintained through the end of the report period and security officers remained alert to their duties.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on February 18 and 19, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X2 Pre-Decisional Enforcement Conference Summary

On January 16, 1997, a pre-decisional enforcement conference was held at the NRC Region I offices in King of Prussia, Pennsylvania. The meeting was held to discuss (1) Unit 1 operation with two pressurizer power operated relief valve block valves shut for an extended period of time and (2) Deficiencies associated with leak sealant repairs on the Unit 2 reactor head vent system. The senior representatives present were Mr. William

Kane, Deputy Regional Administrator, NRC Region I and Mr. James Cross, President, Generation Group, Duquesne Light Company. A copy of the licensee's slides presented at the meeting is included in attachment B.

X3 Licensee Senior Management Changes

On January 19, 1997, Mr. Ronald L. LeGrand assumed the duties of Division Vice President, Nuclear Operations Group and Plant Manager for Beaver Valley Power Station. Mr. LeGrand has previously held two SRO licenses and held various positions with Georgia and Alabama Power Company including Shift Supervisor, Operations Superintendent, Manager of Operations, and Manager of Health Physics and Radiochemistry.

Mr. Tom Noonan, prior Division Vice President, Nuclear Operations Group and Plant Manager, was selected for the position of Technical Assistant to the Senior Vice President and Chief Nuclear Officer.

ATTACHMENT A

PARTIAL LIST OF PERSONS CONTACTED

DLC

R. LeGrand, Vice President, Nuclear Operations/Plant Manager
S. Jain, Vice President, Nuclear Services
L. Freeland, Manager, Nuclear Engineering
B. Tuite, General Manager, Nuclear Operations
C. Hawley, General Manager, Maintenance Programs Unit
R. Brosi, Manager, Nuclear Safety
J. Arias, Manager, Licensing
K. Ostrowski, Manager, Quality Services
R. Vento, Manager, Health Physics
M. Johnston, Manager, Security
D. Orndorf, Manager, Chemistry
F. Schuster, Manager, System and Performance Engineering
G. Storolis, Unit 2 Operations Manager
A. Dulick, Manager, Operations Experience
R. Hart, Senior Licensing Supervisor

NRC

D. Kern, SRI
G. Dentel, RI
F. Lyon, RI
P. Eselgroth, Region I, DRP

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 92700:	Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901:	Follow-up, Operations
IP 92902:	Follow-up, Maintenance
IP 92903:	Follow-up, Engineering
IP 92904:	Follow-up, Plant Support
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED AND DISCUSSED

Opened

50-334(412)/96010-01	URI	Repetition of Configuration Control Problems Despite Previous Corrective Actions (Section O1.7).
50-334/96010-03	URI	Potential Unit 1 RWST Heat Trace Design Discrepancies (Section M2.1)
50-334(412)/96010-04	VIO	Failure to Properly Certify Vendor for Safety Related Work in Accordance with QSL (Section M8.1)
50-412/96010-05	URI	EDG 2-1 Operability with 2EGS-19 Closed (Section E2.3)
50-334/96010-06	VIO	Failure to Have Criticality Monitor for New Fuel Storage Area (Section E8.1)

Closed

50-334(412)96009-01	URI	Proper Verification of QSL Prior to Using Vendor Services (Section O8.4)
50-412/96009	LER	Missed Technical Specification Surveillance Test - Quadrant Power Tilt Ratio Calculation (Section O8.2)
50-334/96013	LER	Failure to Perform Gaseous Waste Disposal System Oxygen Testing as Required by Technical Specifications(Section O8.3)
50-412/96010-02	NCV	Failure to Perform TS Required QPTR Calculation Surveillance (Section O8.2)

Discussed

50-412/95080-01	URI	Independent Verifications of Valve Position Not Performed as Required by Procedure (Section O1.7)
50-334(412)/95080-04	URI	Mispositioning of 2SWS-82 and Two Instrument Root Valves Due to Operator Error or Poor Work Practices (Section O1.7)

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
BCO	Basis for Continued Operation
BVPS	Beaver Valley Power Station
CATS	Commitment Action Tracking System
CCR	Component Cooling Reactor
CR	Condition Report
CR	Control Room
CREST	Condition Report Evaluation and Status Tracking System
CRPA	Condition Report Program Administrator
DLC	Duquesne Light Company
ECR	Employee Concern Resolution
EDG	Emergency Diesel Generator
EM	Engineering Memorandum
EOP	Emergency Operating Procedure
ERT	Event Review Team
ISEG	Independent Safety Evaluation Group
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MSR	Moisture Separ[illegible]eheater
MWR	Maintenance W[illegible]equest
NCV	Noncited Violation
NPDAP	Nuclear Power Division Administrative Procedure
NSA	Normal Switch Alignment
NSRB	Nuclear Safety Review Board
NSS	Nuclear Shift Supervisor
OEDM	Operating Experience Department Manual
OOS	Out of Service
OST	Operational Surveillance Test
PDR	Public Document Room
PMP	Preventive Maintenance Procedure
PMT	Post Maintenance Testing
QA	Quality Assurance
QPTR	Quadrant Power Tilt Ratio
QSDR	Quality Services Deficiency Report
QSL	Qualified Suppliers List
QSU	Quality Services Unit
RCA	Root Cause Analysis
RCP	Reactor Coolant Pump
RHS	Residual Heat Removal System
RP&C	Radiological Protection and Chemistry
RS	Recirculation Spray
SG	Steam Generator
SNM	Special Nuclear Material
SS	Shift Supervisor
SUS	Saybolt Universal Seconds
SVP-CNO	Senior Vice President - Chief Nuclear Officer
SWS	Service Water System

TM	Temporary Modification
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WGDT	Waste Gas Decay Tank

ATTACHMENT B

Predecisional Enforcement Conference

NRC and Duquesne Light Company

January 16, 1997

King of Prussia, PA

Duquesne Light

Duquesne Light Participants

◆ J. E. Cross	President, Generation Group
◆ S. C. Jain	Vice President, Nuclear Services
◆ R. L. LeGrand	Vice President, Nuclear Operations Group & Plant Manager
◆ B. Tuite	General Manager, Nuclear Operations
◆ L. R. Freeland	Manager, Nuclear Engineering
◆ C. A. Hawley	General Manager, Maintenance Programs Unit
◆ K. L. Ostrowski	Manager, Quality Services Unit
◆ J. Arias	Director, Licensing
◆ R. D. Hart	Supervisor, Compliance

Agenda

◆ Opening Remarks	S. C. Jain
◆ Chronology	R. D. Hart
◆ Root Cause	S. C. Jain
◆ Corrective Actions	S. C. Jain
◆ Beyond Design Basis	S. C. Jain
◆ Safety Significance	S. C. Jain
◆ Closing Remarks	J. E. Cross

Chronology

- 1979-1980: NRC IE Bulletin 79-14 review.
- 1980-1982: Unit 1 changes normal position of PORV Block valves to 2 of 3 closed.
- 1980-1981: NRC Inspection Reports 80-27, 80-30, & 81-10 discuss DLC commitments.
- 1981: NRC issues license amendment #39 for BVPS Unit 1.

Chronology (cont.)

- 1982-1986: Undocumented discussions between DLC and the NRC on Appendix R concerns for the PORVs.
- 12/90: DLC responds to GL 90-06.
- 10/92: DLC submits the IPE for Unit 1.
- 04/94: DLC submits TS change request as per GL 90-06.

Chronology (cont.)

- 3/95: DLC responds to an NRC Request for Additional Information about the Unit 1 IPE.
- 5/95: NRC issues TS Amendment 187/69 for Units 1 & 2 to incorporate GL 90-06.
- 9/96: Senior Resident Inspector questions the PORV Block Valve normal alignment.

Chronology (cont.)

- 9/25/96: Nuclear Safety Review Board (NSRB) reviewed a 10 CFR 50.59 evaluation to operate with the 3 PORV Block valves open.
- 9/30/96: NRC issued SER for Unit 1 IPE.
- 10/08/96: PORV Block valves were opened on Unit 1.

Root Cause

- The original commitment to restore the PORV Block valve configuration to open was not followed.
- The processes in place in 1980 were insufficient to enable resolution of this deviation from the UFSAR.
- BVPS personnel did not question the configuration and accepted it as normal alignment.

Corrective Actions

- NSRB reviewed and concurred with a 10 CFR 50.59 evaluation to restore the PORV Block valves to open.
- DLC will conduct a detailed review of the Unit 1 and 2 UFSARs as described in DLC letter to the NRC dated 12/26/96.
- A review was completed by the Quality Services Unit for selected IE Bulletin 79-14 modifications.

Corrective Actions (cont.)

- DLC performed a limited scope review of the Unit 1 UFSAR against the operations manual drawings & normal system alignment. A similar review of the Unit 2 UFSAR is in progress.
- This event and the importance of UFSAR compliance is being reviewed with appropriate members of the Nuclear Power Division.

Corrective Actions (cont.)

- Procedural guidance will be developed to define the process of formally communicating IPE insights to the plant and plant input to the IPE.
- Past IPE revisions will be reviewed to ensure that vulnerabilities identified were properly dispositioned.

Corrective Actions (cont.)

- The UFSAR for each unit is being placed on the site computer network in a text searchable format.
- Commitment tracking has been improved.
- Process controls are in place to address changes in normal system alignment.

Beyond Design Basis

- IPE review of the ATWS event showed a vulnerability due to the PORV Block valve configuration, but to reach an RCS overpressure concern requires a series of events which are beyond the design basis.
- Revisions to the IPE for Unit 1 have changed the magnitude of the contribution to the CDF from the PORV Block valve configuration.

Safety Significance

- The PORV Block valve operating configuration was not in compliance with the system description provided in the UFSAR.
- This operating configuration did not prevent use of the PORVs from the control room in the Emergency Operating Procedures.

Safety Significance (cont.)

- The PORV and Block valve operating configuration was bounded by the UFSAR Chapter 14 accident analysis.
- This operating configuration had no adverse safety significance for the Chapter 14 Accident Analysis.