U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Report Nos.	50-334/97-08, 50-412/97-08
Docket Nos.	50-334, 50-412
Licensee:	Duquesne Light Company (DLC) Post Office Box 4 Shippingport, PA 15077
Facility:	Beaver Valley Power Station, Units 1 and 2
Inspection Period:	October 5, 1997 through November 15, 1997
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EXECUTIVE SUMMARY

Beaver Valley Power Station, Units 1 & 2
NRC Inspection Report 50-334/97-08 & 50-412/97-08

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of announced inspections by regional inspectors in the areas of radiation protection, radioactive effluent control, and inservice inspection.

Operations

- Rod cluster control assembly (RCCA) R-19 was mispositioned during insert change-outs due to inadequate position verification by contractor personnel and inadequate supervisory oversight of the evolution by DLC staff. Inspectors assessed that the licensee root cause analysis for the RCCA mispositioning was thorough and that DLC took reasonable corrective actions to prevent recurrence. (Section O1.2)

- Tagging the Unit 1 containment iodine fans and the steam generator blowdown tank out-of-service, even though the equipment was required in some emergency response procedures, was an isolated instance due to inadequate review and implementation of the Retired Equipment Program. (Section O3.1)

- Operators demonstrated a strong questioning attitude in identifying a longstanding discrepancy in the auxiliary feedwater surveillance test. (Section O4.1)

- Operators' failure to question the acceptability of charging pump gas accumulation data and lack of system engineering guidance was a weakness. (Section O4.1)

- Operator response to a fuel filter leak during emergency diesel generator (EDG) testing was conservative, and operator response in the control room to the loss of the EDG was appropriate. Inspectors noted good control of event response by control room supervisors. (Section M1.3)

Maintenance

- Poor work practices resulted in a fuel filter leak during EDG testing and a thrust bearing failure during post maintenance testing on an auxiliary feedwater pump. The licensee appropriately dispositioned the failures in accordance with the Maintenance Rule. (Sections M1.2 and M1.3)

Engineering

- The licensee's review and corrective actions adequately addressed the inadvertent actuation of the Control Room Emergency Breathing Air Pressurization System (CREBAPS) on October 6, 1996. The CREBAPS Focused Design Review conducted in response to the event was a thorough evaluation of the system and provided good recommendations for resolving the longstanding problems. However, the long-term action to eliminate the spurious activation of this engineered safety features system has not been implemented yet, showing a slow response on the licensee's part to resolve the longstanding operator work-around. (Section O8.1)

- Engineers determined that under certain conditions the voltage supplied to the Unit 1 nuclear instrumentation system power supplies could potentially adversely affect the reactor trip system protective action functions. Engineers' performance during assessment of this issue and extent of condition reviews was conservative and demonstrated a strong questioning attitude. Corrective actions, including design change implementation, were timely and technically sound. (Section E1.1)

- The licensee's team evaluating the gas binding events for the Unit 2 High Head Safety Injection (HHSI) pumps uncovered weaknesses in the original engineering analysis performed to establish venting frequencies. Strong questioning by licensee management and team members led to these findings. The venting frequency established in 1988 to ensure minimal gas accumulation in the suction lines was inadequate to prevent gas binding of the Unit 2 HHSI pumps. The inadequate corrective actions to preclude gas binding of the pumps were addressed in NRC Inspection Report 50-334 and 412/97-07. Further, the inspectors determined, venting of the HHSI pump suction lines immediately prior to TS surveillances may be a violation of NRC requirements pertaining to test validity and is unresolved. (Section E2.1)

- The licensee's inservice inspection program plan for Unit 1, with relief requests, was satisfactorily maintained and implemented. The non-destructive examination personnel were properly qualified and certified, examination procedures were adequate to assure valid examinations, and deficiencies were appropriately evaluated and resolved. The new data management software appeared to be effective. (Section E8)

Plant Support

- The program for control of radiological work during the Unit 1 refueling outage was generally effective; however, one violation of NRC requirements was identified regarding radiation worker knowledge of radiation levels in their work and transit areas. (Section R1)

- Overall, the radioactive liquid and gaseous effluent control programs were good. The Radiation Monitoring System (RMS) reliability was adequate; however, a violation pertaining to RMS calibration practice was noted. (Section R2.1)

- The ventilation system surveillance program for radioactive effluent control was well-implemented. (Section R2.2)

- Good quality control and quality assurance programs were established for radioactive effluent control. (Section R7)

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Report Details

Summary of Plant Status

Unit 1 began this inspection period in Mode 6 (refueling) for the 12th refueling outage. On October 10, the reactor vessel was defueled. On October 20, fuel reloading commenced and the unit re-entered Mode 6. On October 29, the reactor vessel head was tensioned and the unit entered Mode 5 (cold shutdown).

Unit 2 operated at 100% power this 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 Mispositioned Rod Cluster Control Assembly (RCCA)

a. Inspection Scope (92901)

Inspectors reviewed the licensee root cause analysis for the mispositioning of an RCCA in the spent fuel pool. The review included interviews with selected staff and managers, and review of applicable refueling procedures, Nuclear Power Division Administrative Procedures (NPDAPs) regarding vendor services, work location conditions, and corrective actions.

b. Observations and Findings

During RCCA eddy current testing and insert change-outs on October 12, RCCA R-19 was incorrectly inserted into spent fuel pool (SFP) rack location M107 instead of N107 following removal from the eddy current test stand. The RCCA movements were being performed in accordance with Refueling Procedure Book III - 1RP-12R-3.22, "Insert Changeouts, Reposition Fuel Assemblies, and Assembly Verification in Spent Fuel Pit."

Movement of the RCCAs was conducted by two contractor personnel, a SFP bridge operator and a spotter, and a DLC refueling engineer assistant. Shortly after the

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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.

movement of RCCA R-19 to its post-inspection location in the SFP, the bridge operator realized that it had been moved to the wrong location. Contractor supervision, the nuclear shift supervisor, and the DLC Refueling Supervisor were immediately notified. A fuel assembly handling deviation report was prepared and approved in accordance with procedure and R-19 was moved to its proper location. If the positioning error had not been recognized by the bridge operator, refueling procedures contained additional checks later in the process which would likely have caught the error.

DLC senior management learned of the mispositioned RCCA two days afterward when Condition Report 971817 was reviewed during processing. All assembly, insert, and tool movement was halted until an investigation was completed and corrective actions were put in place to prevent recurrence. The DLC root cause analysis highlighted the following deficiencies:

1. Poor self-verification techniques were used by the contractor personnel. Contributing factors were poor lighting on the index rail and the light blue color of the lettering.

2. The refueling assistant did not perform independent verification of RCCA position. The refueling assistant had no formal training and there was no pre-evolution briefing.

Corrective actions for the mispositioning of R-19 included: changes were made to enhance the refueling procedures, a formal training program was initiated for refueling engineer assistants, the lighting was improved at the index rails, and an ISEG review of the event was initiated.

Inspectors also reviewed the vendor oversight requirements of NPDAP 9.8, Rev.4, "Request for Contracted Services," and the current Rev.5, and assessed that the mispositioning did not involve a programmatic concern with vendor control. The root cause analysis and recommended corrective actions were presented to the Nuclear Safety Review Board. The inspectors noted that having the Plant Manager present the analysis and recommended corrective actions diminished the independence of the NSRB review and subsequent recommendations to the Plant Manager. Inspectors assessed that the licensee root cause analysis for the RCCA mispositioning was thorough and that DLC took reasonable corrective actions to prevent recurrence.

TS 6.8.1.a requires that, "Written procedures shall be established, implemented, and maintained covering...the applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978." Regulatory Guide 1.33 includes procedures for refueling. Mispositioning RCCA R-19 was a failure to implement refueling procedure 1RP-12R-3.22 and was a violation of TS 6.8.1.a. This non-repetitive, 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 50-334/97-08-01)**.

c. Conclusion

RCCA R-19 was mispositioned during insert change-outs due to inadequate position verification by contractor personnel and inadequate supervisory oversight of the evolution by DLC staff. The misposition was immediately recognized by the personnel involved and immediate corrective actions were taken to move the RCCA to its correct position. Inspectors assessed that the licensee root cause analysis for the RCCA mispositioning was thorough and that DLC took reasonable corrective actions to prevent recurrence.

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 1 Containment
- Unit 1 Residual Heat Removal System

O3 Operations Procedures and Documentation (92901)

O3.1 (Closed) Unresolved Item 50-334 and 412/97-07-01: Retired Equipment Program

Inspectors reviewed the Retired Equipment Program following the licensee discovery that some equipment was tagged as "retired in place" that was required for use in emergency operating procedures. The issue and the licensee's immediate corrective actions were documented in NRC Inspection Report 50-334 and 412/97-07, Section O3.1.

The licensee extent of condition review did not identify any additional equipment tagged out that was required for use in emergency or abnormal operating procedures (EOPs or AOPs). The candidate components and systems identified by system engineers and operators for potential retirement were entered into the evaluation process per Nuclear Power Division Administrative Procedure 8.33, Rev.0, "Retired Equipment Program." The Director, System Engineering, expected the evaluations to be completed by December 15. No additional concerns were noted by the inspectors.

Inspectors concluded that there were no safety consequences to having the containment iodine fans and the steam generator blowdown tank (1FW-TK-1) tagged out as "retired in place," because the equipment was not safety-related and was not depended upon in accident analysis. In addition, alternate methods of emergency response other than the iodine fans and blowdown tank were proceduralized. Inspectors assessed that tagging the equipment out-of-service was an isolated instance due to inadequate review and implementation of the Retired Equipment Program.

TS 6.8.1.a requires that, "Written procedures shall be established, implemented, and maintained covering...the applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978." Regulatory Guide 1.33 includes procedures for combating emergencies and other significant events. Equipment was retired-in-place without recognizing that it was required in certain EOPs. Failure to maintain the EOPs current was a violation of TS 6.8.1.a. This non-repetitive, 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 50-334 and 412/97-08-02)**.

O4 Operator Knowledge and Performance

O4.1 Questioning Attitude of Operators

a. Inspection Scope (71707)

During routine control room tours, inspectors observed operator activities and response to degraded conditions.

b. Findings and Observations

In general, the inspectors noted that operators were knowledgeable of plant conditions and out-of-service equipment. The inspectors observed two particular instances that reflected on the questioning attitude of the operators.

Operators questioned steps in the surveillance test for the auxiliary feedwater pumps. During performance of auxiliary feedwater (AFW) pump testing, the manual discharge isolation valve is shut to prevent AFW flow to the steam generators. In accordance with Technical Specification (TS) 4.7.1.2.a.4, an operator is stationed at the pump and is in constant communication with the control room. If needed, the operator is expected to open the discharge valve. The operators questioned whether this is physically possible due to the pressure differential across the valve. Engineering calculations show that the operator would not be able to open the valve. The issue and corrective actions are being tracked under Condition Report 971892. The inspectors noted that operators displayed an excellent questioning attitude in identifying this longstanding practice of stationing the operator at the pump.

Since the beginning of September 1997, Quality Service personnel have performed ultrasonic examinations to determine gas accumulation in the suction lines of the charging pumps (see Section E2.1 and NRC Inspection Report 50-334 and 50-412/97-07). The gas accumulation was reported to the control room operators in units of inches. Based on interviews, the inspectors determined that the operators did not have a clear understanding of what the values meant nor their impact on operability of the charging pumps. After inspectors' questioning and discussions with operations and system engineering management in October, the system engineering staff provided guidance to the operators on the quality service examinations results. The inspectors observed that the current practice provided the operators with a well defined gas volume limit to make an operability determination. The lack of adequate guidance, prior to the inspectors' questioning of the issue, resulted from poor questioning from the operators and failure of system engineers to provide appropriate guidance to the operators.

c. Conclusion

The inspectors had mixed observations with regard to the questioning attitude of the reactor operators. In one instance, operators using a strong questioning attitude identified a longstanding discrepancy in an AFW pump test. However, operators' failure to question the acceptability of charging pump gas accumulation data was a weakness.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Licensee Event Report (LER) 50-334/96-012: Entry into Technical Specification 3.0.3 Due to Isolation of Control Room Emergency Breathing Air Pressurization System.

a. Inspection Scope (71707)

On October 6, 1996, Unit 2 control room operators inadvertently actuated the Control Room Emergency Breathing Air Pressurization System (CREBAPS). CREBAPS provides pressurized air to the dual unit control room. Unit 1 operators isolated CREBAPS (to mitigate the consequences) and, as a result, entered into Technical Specification (TS) 3.0.3. This event was previously discussed in NRC Inspection Report 50-334 and 50-412/96-08. The inspectors reviewed LER 50-334/96-012 and other licensee documents. The inspectors also interviewed licensee personnel to evaluate corrective actions, the effects of the CREBAPS bottle isolation operator work-around, and reliability of the system. The following documents were reviewed:

- "CREBAPS Focused Design Review Report," Rev. 1
- Problem Report 2-96-610, "Inadvertent CREBAPS Actuation"
- Unit 1 Maintenance Rule System Basis Document, "Area Ventilation Systems - Control Area, System 44A," Rev. 3
- 2DBD-44A2, Rev. 3, Design Basis Document for Area Ventilation Systems - Control Area
- Unit 2 Shift Logs for August 1997
- Unit 1 Equipment Out of Service Log, 01/01/97 - 10/31/97
- Unit 1 Work Around Log, dated 09/25/97.

b. Observations and Findings

There have been 20 LERs written at BVPS 1 and 2 since 1987 due to spurious CREBAPS actuations and entry into TS 3.0.3. Most of the inadvertent actuations were due to radiation monitor noise and electronic sensitivity problems. To prevent an inadvertent air bottle discharge during testing of the radiation monitors, surveillance procedures were revised to isolate the CREBAPS bottles, and TS 3.7.7.1 (Unit 1) and TS 3.7.7 (Unit 2) were amended to allow isolation of the CREBAPS bottles for up to 8 hours. The licensee identified the isolation of the bottles as an operator work-around in August 1995. There have been 5 spurious actuations of the CREBAPS system this year. There were no discharges of the system because the CREBAPS bottles were isolated through the proceduralized operator work-around.

Licensee corrective actions listed in LER 50-334/96-012 have been completed and are appropriate to the specifics of this event. As part of the corrective actions, the licensee performed a focused design review of the CREBAPS. The inspectors assessed that the CREBAPS Focused Design Review Report was a very thorough evaluation of the system, and the recommended corrective actions addressed the root causes of the spurious actuations. Many of the recommended corrective actions of the Focused Design Review have been implemented and have been beneficial. The licensee installed Technical Evaluation Report (TER) 10587 in late June for control room area radiation monitor RM-218A, and in September for RM-218B. This TER improved grounding in the instrument rack, improved coaxial shielding, installed snubbers and in-line resistor-capacitor filters, and installed a delay modification in the radiation monitors to prevent false alarms upon startup or following a source check. These modifications were positive improvements. However, several spurious actuations have occurred since the modifications. System engineering staff concluded that additional corrective action to install a time delay in the radiation monitor actuation circuitry is necessary; however, it has not been scheduled yet. Therefore, the longstanding operator work-around has continued.

Through review of the August Unit 2 operating shift logs, the inspectors determined that portions of the CREBAPS system had been isolated 21% of the time. Approximately 3% of the time was due to the testing and surveillance operator work around, 7% for periodic maintenance, and 11% due to unscheduled corrective maintenance. The inspectors interviewed the licensee system engineer, the maintenance rule program coordinator, and PRA engineer to determine the applicability of system unavailability to the Maintenance Rule. The CREBAPS system was considered a non-risk-significant standby system and was tracked through plant level criteria, with a limit on maintenance preventable functional failures (MPFFs) tracked for the standby safety-related functions. The inspectors determined that this level of tracking was in accordance with the Maintenance Rule.

c. Conclusions

The licensee's review and corrective actions adequately addressed the inadvertent actuation of the Control Room Emergency Breathing Air Pressurization System (CREBAPS) on October 6, 1996. The CREBAPS Focused Design Review conducted in response to the event was a thorough evaluation of the system and provided good recommendations for resolving the longstanding problems. However, the long-term action to eliminate the spurious activation of this engineered safety features system has not been implemented yet, showing a slow response on the licensee's part to resolve the longstanding operator work-around.

O8.2 (Closed) LER 50-334/97-004-01 (92901): Failure to Test Post DBA Hydrogen Control System Recombiners in Accordance with Technical Specifications.

The issue was documented in NRC Inspection Report 50-334 and 412/97-02, Section M8.2. No new issues were raised in the LER revision. The scheduled completion dates for corrective actions were revised or updated.

O8.3 (Closed) LER 50-334/97-032 (92901): Emergency Diesel Generator (EDG) Automatic Start During Bus Transfer from Unit to System Station Transformer.

The issue was documented in NRC Inspection Report 50-334 and 412/97-07, Section E2.3. No new concerns were raised in the LER. Inspectors noted that the licensee has submitted a TS amendment request (Proposed Operating License Change Request No.243, dated November 4, 1997) for Unit 1 to revise the emergency bus undervoltage trip setpoint, allowable value and time delay for EDG start. This is intended to be a permanent corrective action to prevent unnecessary EDG starts during fast bus transfers and while starting reactor coolant pump 1A. The licensee also intends to review the TS amendment history associated with the event to determine if the existing T/S amendment process has any adverse impact and to identify and implement appropriate enhancements, if necessary, by February 27, 1998.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Routine Maintenance Observations (62707)

The inspectors observed selected maintenance activities on important systems and components. The activities observed and reviewed are listed below.

- 1PMP-13RS-P-Leak Test-1M — Recirculation Spray Pump Leak Test
- DCP 2298 — Additional Small Bore Pipe Supports Upgrade
- DCP 2209 — ARPI Electronics Upgrade

- MWR 061194 FW-P-2 AFW Pump Terry Turbine Overhaul

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

Motor driven auxiliary feedwater pump FW-P-3A was overhauled during the refueling outage under MWR 067122. During post-maintenance testing, the inboard pump bearing was destroyed. Investigation revealed that the balance drum had not been set correctly by maintenance technicians during pump reassembly. The root cause was attributed to poor workmanship. The issue was documented on Condition Report 971956. Following repairs, the pump was tested satisfactorily and returned to service. The licensee concluded that the issue was not a maintenance preventable functional failure (MPFF) under the Maintenance Rule because the pump was out-of-service for overhaul and was not required in Mode 5 (cold shutdown), and the failure was discovered during post-maintenance testing. Inspectors discussed the issue with system engineering staff and agreed that it was not an MPFF. Corrective actions to prevent recurrence were under evaluation at the end of the period.

M1.2 <u>Routine Surveillance Observations (61726)</u>

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

- 1OST-36.1, Rev.17 Diesel Generator No.1 Monthly Test
- 1OST-24.8, Rev.6 Motor Driven AFW Pumps Check Valves and Flow Test
- 1OST-36.4, Rev.9 Diesel Generator No.2 Automatic Test
- 1OST-7.11, Rev.11 CHS and SIS Operability Test
- 1OST-13.11, Rev.4 QS System Operability Test
- 2OST 26.1, Rev. 13 Turbine Throttle, Governor, Reheat Stop and Intercept Valve Test
- 1OST-47.2, Rev.18 Containment Integrity Verification

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.

M1.3 Leak on Unit 1 EDG Fuel Oil Filter (71707, 92902)

1OST-30.4 performs an automatic start of emergency diesel generator (EDG) No.2 by simulating a loss of offsite power to 4kV bus 1D. Immediately after the EDG start, a Train "B" safety injection signal is actuated to ensure proper sequencer operation. Required loads are then verified to trip and then sequence onto emergency bus 1DF. Following logic functional testing, EDG trips are disabled and a load reject test of greater than 600KW is performed on the EDG.

During test performance on November 8, the EDG undervoltage start and sequencer operation was satisfactory. However, about 30 seconds into the run, operators noted fuel oil spraying from engine mounted duplex fuel oil filter 1EE-FL-10B. Operators shut the EDG fuel rack to stop the diesel and the leak. Loss of the EDG resulted in loss of power to the 4kV bus 1DF, 480V bus 9P, and all "B" train 120VAC loads. Vital buses 2 and 4 remained energized from their respective batteries. There was minimal impact on the plant due to the initial lineup for the test. Operators restored power to the affected buses in accordance with applicable alarm response procedures within 45 minutes. Inspectors observed the event from the control room and toured the EDG room shortly afterward. The amount of fuel oil spilled was small due to quick operator action in securing the EDG. Inspectors assessed that operator response at the EDG to the fuel leak was conservative, and operator response in the control room to the loss of the EDG was appropriate. Inspectors noted good control of event response by control room supervisors.

The fuel oil filter gasket was inspected, reseated, and tested satisfactorily. Maintenance technicians concluded that the gasket had not been sufficiently compressed during installation, possibly because a new gasket material was being used. The issue was documented under Condition Report 972111 for evaluation and corrective actions. The surveillance test on the EDG was successfully performed on November 10.

III. Engineering

E1 Conduct of Engineering

E1.1 Vital Bus Voltage Evaluation

a. Inspection Scope (37551, 62700, 92903)

While reviewing plans to upgrade existing solid state protection system (SSPS) relays, engineers identified a concern regarding the adequacy of voltage supplied to the nuclear instrumentation system (NIS) power supplies. The inspectors interviewed personnel, reviewed design documents and observed design change implementation activities to evaluate licensee resolution of this issue.

b. Observations and Findings

On October 8, 1997, engineers determined that under certain conditions the voltage supplied to the Unit 1 NIS power supplies could be outside of the vendor's recommended range (118 $\pm$2.5 volts). This condition could potentially adversely affect the reactor trip system (RTS) protective action functions that respond to power level data from the NIS. The inspectors discussed the issue with operations and engineering personnel and noted that the issue was properly reported to the NRC in accordance with 10 CFR 50.72 and 10 CFR 50.73.

The inspectors observed that engineers were conservative in assessing a cumulative worst case scenario. Engineers applied the maximum allowable variation in the invertor and regulating transformer output voltages combined with the worst case voltage drop from the transformer to the NIS protection rack (due to various vital bus and NIS protection rack loading). Engineers also applied the most restrictive available tolerance band to the NIS power supplies. The Unit 2 NIS power supplies have a vendor specified voltage tolerance of 118 $\pm$5% volts. Although the Unit 1 and Unit 2 NIS power supplies are very similar, the documented tolerance for Unit 1 (found in the vendor troubleshooting manual) is much more restrictive. Even though the Unit 1 NIS voltages were outside of vendor recommendations, engineers believe power supplies were likely to have functioned properly as installed, because they were similar in design to the Unit 2 power supplies. Notwithstanding, since documentation of acceptable NIS performance outside of the specified voltage band was not available, engineers recommended upgrading the existing Unit 1 NIS power supply voltage transformers. Engineers determined that the existing Unit 2 NIS power supply was acceptable, based on design drawings, calculations, and voltage measurements.

As an immediate action, operators verified that voltages were within the vendor specified range each operating shift. In addition, maintenance records demonstrated that the voltages were within the specified range when last verified per periodic maintenance. Engineers reviewed Unit 1 operating history documents and did not identify any actual plant conditions during which voltage was outside of the vendor's recommendations. The unit was in cold shutdown at the time of discovery. Engineers closely communicated with the vendor, initiated a design change to upgrade the power conditioning, and reviewed the potential extent of condition for additional vital bus loads for both units. The inspectors determined that initial actions were timely and technically sound.

Design change package (DCP) 2296, "Vital Bus Voltage Requirements", was written to upgrade the NIS power supply regulating transformers (118 $\pm$1% volts) and improve connections from the vital bus distribution panels. The inspectors reviewed the DCP and observed portions of the field installation and testing. The DCP was properly implemented and closely coordinated with operations personnel to establish prerequisite plant conditions for installation and testing.

Calculation Nos. 8700-E-231(232) were initiated to model vital bus component performance for all four vital buses and downstream components. These calculations were nearing completion at the end of this report period. No additional safety related load discrepancies had been identified. Based on the results of the completed Unit 1 calculations, engineers will determine whether a detailed Unit 2 analysis is needed.

c. Conclusions

Engineers determined that under certain conditions the voltage supplied to the Unit 1 NIS power supplies could potentially adversely affect the reactor trip system protective action functions. Engineers' performance during assessment of this issue and extent of condition reviews, was conservative and demonstrated a strong questioning attitude. Corrective actions, including design change implementation, were timely and technically sound.

E2 Engineering Support of Facilities and Equipment

E2.1 (Closed) Unresolved Item (URI) 50-334 and 412/97-07-04: Adequacy of the High Head Safety Injection Pump Surveillance Tests to Ensure Operability

a. Inspection Scope (37551)

The inspectors reviewed the adequacy of the surveillance procedure to determine functionality of the high head safety injection (HHSI)/charging pumps. The inspectors interviewed operators, system engineers, and system engineering management. The inspectors reviewed the following documents:

- Inservice Testing (IST) data for the Unit 2 HHSI pumps since 1991;
- Completed surveillance procedures for Unit 2 HHSI pumps for 1996 and 1997;
- The last five revisions to the surveillance procedures for the Unit 2 HHSI pumps;
- Minimum operating performance curves (located in the Inservice Testing Program for Pumps and Valves)

b. Observations and Findings

The inspectors identified several issues in NRC Inspection Report 50-334 and 412/97-07 that were related to the adequacy of the Unit 2 surveillance procedures 2OST-7.4(5)(6), "Centrifugal Charging Pump [2CHS*P21A(B)(C)]," to determine functionality of the HHSI pumps.

Surveillance Procedure/IST Acceptability

The surveillance procedures require that at specific flow rates (~200 gpm), operators obtain IST data including pump bearing temperatures, motor bearing temperatures, pump vibration data, pressures, and flow rates. After recording this data, the procedures allow throttling of the flow to meet the Technical Specification (TS) required differential pressure. Based on review of the TS, the minimum operating performance curves, and basis for the differential pressure values, the inspectors determined that the procedure was acceptable to measure and determine whether pump performance met the TS required differential pressures.

The acceptance criteria in the surveillance procedure require that the pumps operate within the limits of the ASME Section XI IST program. The inspectors determined from past IST results and procedure reviews, that the data was collected at a constant flow rate which ensured the data would provide meaningful trending information. The ASME acceptance criteria for differential pressure were not clearly linked to the flow rate due to poor procedure human factors; however, the inspectors determined the performance data was properly evaluated to correlate to the acceptance criteria. Based on engineering memorandums and IST program information reviewed, the inspectors determined that the licensee had established a nexus between the acceptance criteria and the minimum operating performance curve. The minimum operating performance curve establishes the required flow for safety analysis. This closes URI 50-334 and 412/97-07-04.

Additional Background Information

In March 1988, Beaver Valley experienced gas binding of the Unit 2 HHSI pump (2CHS-P21A). NRC Information Notice 88-23, "Potential for Gas Binding of High-Pressure Safety Injection Pumps During a Loss-of-Coolant Accident," highlighted the industry issue. Engineering performed model testing and ultrasonic testing (UT) examinations of piping to determine gas growth rates. Several solutions were evaluated and a manual venting path was established for both units. The venting times were established based on UT measurements of gas accumulation in 1988 and an estimated maximum gas accumulation limit (based on prior history).

The licensee did not find the Unit 2 UT examination results performed in 1988 during records reviews in 1997. The conclusions derived (gas accumulation rates) from those results were documented and used to establish the pump venting frequencies. Unit 1 gas accumulation rates were established based on 48 hours of data taken in 1988. Between 1989 and August 1997, the licensee did not conduct UT testing for Unit 1 or Unit 2 to verify gas accumulation rates were valid. Unit 2 UT examinations conducted since August 1997 showed that the majority of the gas accumulation occurred during pump shutdown and not during steady state conditions. However, the overall Unit 2 gas accumulation rates were bounded by the 1988 conclusions. Additional UT examinations for Unit 1 were conducted on all three Unit 1 HHSI pump suction lines in early November. The gas accumulation rates are still under investigation.

Prior to March 1988, the licensee had experienced 21 safety injection events at Unit 1 without failure of the HHSI pumps. The maximum gas accumulation limit (8.1 cubic feet) was determined using past successful HHSI pump operation and engineering analysis in evaluating the void size during those events. Based on this analysis a maximum gas accumulation limit was established for Unit 1 and Unit 2. The use of Unit 1 data to support a Unit 2 maximum gas accumulation limit may have been inappropriate due to the different piping configurations.

In October 1997, the licensee team investigating the gas binding events assessed that the maximum gas accumulation limit should be reevaluated for Unit 1 and Unit 2. Based on preliminary evaluation, system engineers have established a maximum gas accumulation limit of 0.5 cubic feet for Unit 2. The limit is based on vendor recommendation to minimize entrained gas to 5% by volume. Daily UT measurements on Unit 2 suction lines have been performed to verify that the limit has been met. The Unit 1 preliminary determination of gas accumulation limit will be completed prior to Mode 4 entry. The final evaluation of gas accumulation limit is under investigation by the team for Unit 1 and Unit 2. The licensee is reevaluating the engineering analysis for the original values and vendor information to determine an appropriate maximum gas accumulation limit. This effort includes construction of a model to help address questions on gas accumulation and transportation of that gas to the pump.

In addition, the established vent path was ineffective due to insufficient driving force to move the gas from the charging pump piping to the collection tank. Periodic venting did not always adequately vent the Unit 2 HHSI pump suction lines. The Unit 2 "C" HHSI pump experienced gas binding during multiple starts in June 1993 and during starts in November 1996 and August 1997. The repeated gas binding events were the most likely cause for the pumps' degraded performance and subsequent replacement in September 1997. The inadequate venting and gas binding events were documented in NRC Inspection Report 50-334 and 412/97-07.

Based on the gas binding events that occurred on Unit 2 "C" HHSI pump, the inspectors determined that the established vent path and venting frequencies were inadequate to ensure proper pump performance. The inadequate venting system and the questionable acceptable gas accumulation limits resulted in inadequate venting frequencies. From 1988 to August 1997, the licensee relied on the venting frequencies to maintain acceptable low levels of gas entrainment for operability of the HHSI pumps. The failure to take appropriate corrective actions to preclude gas binding of the pumps was an apparent violation documented in NRC Inspection Report 50-334 and 412/97-07.

Venting Prior to Manual Pump Starts

During review of the surveillance procedure and discussions with system engineers and operations management, the inspectors determined that HHSI pump suction lines were routinely vented prior to performing manual pump starts, including the periodic surveillance test. The procedures allowed venting the HHSI pump prior to starting the pump at the nuclear shift supervisor's discretion. Unit 1 and Unit 2 operators typically vented the HHSI pumps prior to performing the quarterly surveillances, safeguards protection system testing (GO testing), and 18-month full flow testing. The venting prior to pump start was done to eliminate any gas in the system to enhance pump long-term reliability.

The venting frequency established to ensure minimal gas accumulation in the suction lines was inadequate to prevent gas binding of the Unit 2 HHSI pumps. The inspectors determined that venting the suction lines immediately prior to performing the surveillance testing changed the as-found condition of the system from that which would normally be present if the system was automatically called upon to perform its safety function. Changing the as-found condition of the HHSI pump suction lines immediately prior to performing periodic surveillance tests may interfere with the licensee's ability to properly assess the operability of the system. 10 CFR 50, Appendix B, Criterion XI, "Test Control", requires, in part, that "... the test is performed under suitable environmental conditions." Suitable environmental conditions include conditions representative of the expected conditions when the equipment is required to perform its safety function. The normal practice of venting prior to surveillance testing may be a violation of NRC requirements pertaining to the validity of the test results, depending upon the periodic venting program implemented between the surveillance tests. This is considered an unresolved item pending further NRC review. **(URI 50-334 and 412/97-08-03)**.

c. Conclusion

The inspectors observed that the licensee's team evaluating the gas binding events in August 1997 had uncovered weaknesses in the original engineering analysis performed to establish venting frequencies. Strong questioning by licensee management and team members led to these findings. Inspectors identified weaknesses in the licensee's oversight of gas accumulation in the safety significant HHSI system from 1988 to 1997, in that the licensee did not verify the original gas accumulation rate assumptions, and did not verify the adequacy of the periodic vent path used during that time period.

Periodic venting practices established in 1988 to ensure minimal gas accumulation in the suction lines was inadequate to prevent gas binding of the Unit 2 HHSI pumps. The frequency of venting should be based on a good venting method, an established gas accumulation limit, and an established gas accumulation rate. Since the venting method was not effective and the established gas accumulation rate and limits were incorrect, the venting frequency was inadequate. The inadequate corrective actions to preclude the gas binding of the pumps were addressed in Inspection Report 50-334 and 412/97-07. Acceptability of the pre-surveillance test venting that had been in effect is unresolved.

E8 Miscellaneous Engineering Issues

E8.1 Inservice Inspection

a. Inspection Scope (73753, 92903)

An inspection of the inservice inspection (ISI) program was conducted by a regional inspector from October 20-24, 1997. The objective of this inspection was to verify that the inservice inspection (ISI), repair, and replacement of Class 1, 2, and 3 pressure retaining components are performed in accordance with the Technical

Specifications (TS), the applicable ASME Code, NRC requirements, and industry initiatives, including any relief requests granted by the NRC.

The scope of the inspection included the review of the licensee's ISI program plan for Beaver Valley Unit 1, procedures, qualification of inspection/examination personnel, schedule of planned ISIs for the refueling outage 1R12, and observation of ISI work.

b. Observation and Findings

1. The ISI Program Plan

The ISI program plan for the third 10-year interval was submitted to the NRC on September 17, 1997. The plan includes several relief requests and alternate inspection methods. Although the plan has not yet been approved by the NRC, the licensee has implemented the proposed plan with the rationale that many of these relief requests and alternate inspection methods had been approved by the NRC for the previous plan, thus it would be acceptable for the third interval. However, if the NRC does not approve any of the proposed relief requests or alternates, the licensee has two more scheduled "outages" to modify and implement an approved plan.

2. Steam Generator Tube Eddy Current Inspection

Duquesne Light Company (DLC), the licensee for Beaver Valley Unit 1 (BV-1), had nearly completed its steam generator (SG) tube eddy current inspections for the current refueling outage. BV-1 has three Westinghouse Model 51 SGs with carbon steel drilled hole tube support plates and WEXTEX joints in the tubesheet. DLC performed full length bobbin coil eddy current inspections of all active tubes in each SG. The licensee also performed specialized inspections using the plus point probe of the low row U-bends, hot and cold leg top of the tubesheet (TTS), most bobbin coil indications, and rolled plugs. DLC also conducted a secondary side visual inspection of the wrapper supports and found no degradation.

Through bobbin coil inspections, DLC identified four pluggable (i.e., greater than 40% throughwall) wear indications due to cold leg thinning and anti-vibration bar (AVB) wear. The licensee also detected tube support plate (TSP) cracking through bobbin coil inspection and followed up using the plus point probe to confirm about fifteen such indications in the patch plate region. The licensee is evaluating how to disposition the affected tubes.

DLC inspected 100% of the TTS on the hot leg side and 20% of the TTS on the cold leg side in each SG. The axial extent of the tubesheet inspections included six inches above the TTS to three inches below the TTS. On the hot leg side, the licensee reported 127 repairable indications. Most were identified as axially-oriented outside-diameter stress corrosion cracking (ODSCC) located above the TTS in the tube "collar" region (area of heavy tube deposits not removed through sludge lancing). A few were axial and circumferentially-oriented indications located below the WEXTEX expansion transition inside the tubesheet. On the cold leg side, the licensee identified nine axially-oriented ODSCC indications located above the TTS; for this SG, the licensee expanded its inspection scope to include 100% of the TTS region. The longest extent for a circumferential crack was about 90° and the longest axial crack was reported to be about 0.8 inches long. Eight volumetric indications (some pit-like) were found in the TTS region as well.

DLC inspected 100% of the row 1 and 2 U-bends and 20% of the row 3 U-bends. The licensee reported 11 row 1 U-bend indications and 1 row 2 U-bend indication characterized as primary water stress corrosion cracking (PWSCC) and located in the bend tangent. DLC's low row U-bends have been stress relieved.

The licensee performed a 100% inspection of dents >5 volts, a 20% sample of dents >205 volts, and 100% of all dents and dings (dents located in the freespan) >2 volts located between the TTS and the 3rd TSP. No indications were reported.

DLC inspected 100% of its Inconel 600 (I-600) rolled plugs and 20% of its Inconel 690 (I-690) rolled plugs. The licensee reported seven I-600 plug indications. The licensee intends to replace these with I-690 rolled plugs during this outage. No I-690 plug indications were reported.

For the identified degradation mechanism, the licensee has selected the most limiting (based on length, depth and voltage) indications for insitu pressure testing. At the time of this inspection, the pressure testing of SG tubes was in progress. The inspector witnessed one such test from the remote test control location.

3. <u>Qualification/Certification of NDE Personnel</u>

The inspector reviewed the qualification and certification records of approximately seven individuals engaged in non-destructive examination (NDE) of the ISI program. The review indicated that the inspectors were properly qualified by formal and practical training, and were certified to proper levels of inspection/examination responsibility in different examination methods; e.g., visual examination (VT), liquid penetrant (PT), magnetic particle (MT), or ultrasonic examination (UT).

4. <u>Observation of ISI Examinations</u>

The inspector observed/witnessed several NDEs to assess the adequacy of procedures, knowledge and proficiency of test personnel, and the validity of the test results. The following tests were observed:

1. Surface examination by dye penetrant: CH-23-3-5-03, and CH-23-4-F-06 inside containment;

2. Volumetric examination by UT: 1-SA-41-FD24 in the auxiliary building; and

3. Pressure test of steam generator tube: 5A21 from the remote display/control test facility for SG tube examination and tests.

The tests/examinations were performed by knowledgeable and qualified individuals, using approved procedures, materials, and calibrated equipment. The results were properly recorded.

5. Evaluation and Resolution of Deficiency

The inspector reviewed the evaluation and resolution by Engineering of three "unsatisfactory" test results. These deficiencies were documented in Condition Reports 970792, 970793, and 970836, and were related to PT surface examinations.

In all cases, the disposition of the indication by grinding and blending the surface profile to established contour was appropriate.

6. NDE Procedures

The inspector reviewed the following NDE procedure to assess the clarity and technical adequacy of established requirements.

GP-105	Evaluation of PSI/ISI Flaw Indications, Rev. 6
LP-101	Solvent Removable Visible Dye, Rev. 15
MT-201	Magnetic Particle Examination, Rev. 13
UT-301	Linearity of Ultrasonic Instruments, Rev. 9
UT-303	Ultrasonic Examination of Piping Welds, 2" to 6" Thick and Vessels Less than or Equal to 2" Wall Thickness, Rev. 12

The inspector determined that the procedures were clearly written, established technically valid requirements and were appropriately maintained, controlled, and used by NDE personnel.

Additionally, the licensee has implemented a new data management software for tracking and managing ISI program. The new system appears comprehensive and has been successfully used at other utilities.

c. Conclusions

Based on the above observation, review of documentation, and discussions with personnel responsible for ISI program, the inspector concluded that the licensee's ISI program plan is satisfactorily maintained and implemented. The NDE personnel are properly qualified/certified, examination procedures are adequate to assure valid examinations, and deficiencies are appropriately evaluated and resolved. The new data management software appears effective.

E8.2 (Closed) VIO 50-334/96-05-02 (92903): Inadequate Calibration for UT examinations

The above violation pertained to a failure to perform a calibration for UT examination using a reflector perpendicular to the sound beam for examinations with the sound beam to the weld seam (circumferential examinations) on six ASME class 2 pipe weld examinations. Also, for two calibrations (C-96-57 and C-96-46) side drilled holes were not used to construct the distance amplitude correction (DAC) curve.

In response to the Notice of Violation, the licensee initiated corrective actions to resolve the deficiency, and to prevent similar occurrences in the future. The licensee's actions included the following:

1. Problem Reports 1-96-487, 1-96-488 and 1-96-489 were submitted to the Operations Experience Group on May 17, 1996. These problem reports identified the scope of incorrect calibrations and provided technical assessments of the deficiencies identified during the exit meeting on May 16, 1996.

2. An independent review of the problem reports was performed by Materials and Standards Engineering to address potential operability concerns.

3. Independent root cause evaluation using the TapRoot root cause evaluation method was performed on the problems identified.

Actions Taken to Prevent Recurrence

As a result of the recommendations in the root cause evaluations, the following corrective actions were being taken:

1. UT Procedure UT-303 was revised for clarification and to allow ID notch calibration and was demonstrated to the authorized nuclear inservice inspector (ANII).

2. NDE contractor training has been included in procedure QSP 2.5, which provides procedural controls for onsite training of contracted NDE personnel using DLC. NDE procedures.

3. The calibration report forms have been revised to more clearly define calibration orientation and calibration reflectors used.

4. The dissimilar metal welds examined using only the ID notch for calibration were re-examined using a qualified UT technique during 1R12.

The inspector verified the licensee's corrective actions by review of documentation and discussion with cognizant personnel, and found the actions acceptable and effective. Based on the above observation, this item is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

a. Inspection Scope (83750)

The inspectors reviewed the licensee's program for radiation protection during a refueling outage (1R12). Areas reviewed included high and locked high radiation area controls, radiation worker performance indicators, including maintaining occupational exposures as low as is reasonably achievable (ALARA), and radiation worker practices. The inspection was accomplished by a review of plant documents and procedures, interviews with personnel, and walkdowns of the related areas.

b. Observations and Findings

The inspectors reviewed the licensee's performance during the Unit 1 refueling outage (1R12) which commenced in late September. Outage goals previously established included completion of the outage in 40 days (with a challenge goal of 36 days), an occupational exposure goal of not more than 201 person-rem, and a personnel contamination event goal of not more than 180. During the period of this specialist inspection, outage activities included eddy current testing in all three steam generators, reactor head and upper core internals removal, and the first 36 hours of fuel removal.

The inspectors reviewed the licensee's control of high and locked high radiation areas, especially those located in the containment. All areas reviewed, which included the entrances to the steam generator/reactor coolant pump cubicles, were determined to be appropriately controlled, barricaded and posted in accordance with plant technical specifications. Workers interviewed in the high radiation areas were aware of their work area exposure rates and appropriate radiological controls to minimize their exposures. Health physics technicians were observed providing detailed and extensive briefings to workers and providing appropriate job coverage. Of particular note was the licensee's utilization of remote teledosimetry, closed circuit cameras and communication for steam generator eddy current testing. By utilizing this type of control, the licensee was able to significantly reduce total job exposures, especially for the radiological controls technicians, while providing real time exposure rate data so as to minimize steam generator worker exposures.

As noted above, the licensee had established an outage ALARA goal of not more than 201 person-rem, and through day 12 of the outage the exposures appeared to be tracking well, although the licensee does not track exposure against percentage of work completed and the outage was estimated to be two days behind schedule. The inspector noted that the licensee was focused on personnel contamination events (PCEs) and had established an outage goal of not more than 180 PCEs.

During the specialist inspection, the inspectors noted that workers entering the radiologically controlled areas (RCAs) were not checking the posted general area survey maps located at the primary plant staff and contractor entry points, as specified in the licensee's radiation work permits. Since the licensee did not utilize a direct verbal briefing system between workers and the health physics staff prior to entries, it appeared to the inspectors that the potential existed for workers to be in portions of the RCA without knowing the radiological conditions. On October 7th and 8th, the inspectors conducted a random survey of workers located in the general areas of the primary auxiliary building, especially the transit path to the containment personnel hatch, and inside the containment, in the outer annulus regions. None of the ten workers interviewed could identify the radiological conditions in the areas they were standing in or had walked through. None of the workers could identify their nearest ALARA low dose waiting area. The inspectors further noted that workers failed to review the radiological survey maps placed at the two main RCA entrances, as required by their RWPs. Further, the inspectors noted that a number of the posted survey maps at the RCA access points were outdated and did not accurately reflect current plant conditions. Failure of workers to follow instructions contained in their RWPs is a violation of TS 6.8.1.a, which requires that written procedures and instructions be established, implemented and maintained regarding radiation protection procedures. **(VIO 50-334/97-08-04)**.

On two separate occasions, the inspectors observed workers in the containment who appeared to be unaware of their surroundings. One worker was observed lying on the floor on the 692' elevation next to a desk and chair at the health physics control point for that level, while another was outside the "C" steam generator cubicle on the 718' elevation. Neither location was a designated low dose waiting area. Both workers had their eyes closed, and did not open them or notice the inspector until just as the inspector passed them. The inspector notified plant supervisors of his observations, and his concern that personnel, not actively engaged in work in the RCA, should be outside the RCA or in posted ALARA low dose waiting areas. The first example was subsequently documented in a plant condition report.

During tours of the containment, the inspectors noted generally poor radiological housekeeping. The same observation was made by the plant Health Physics Manager, who stressed the importance of this issue at a morning management meeting attended by the inspectors. By the end of the specialist inspection, housekeeping had improved but was still considered poor.

The inspectors also reviewed the license's most recent results from the National Voluntary Laboratory Accreditation Program (NVLAP) of its thermoluminescent dosimetry program. During NRC Inspection Report 50-334 and 412/97-02, the inspectors noted that the licensee had failed test criteria 1, Accident Low Energy Photon. Since that time the licensee has resubmitted 15 test dosimeters, five per month for three months, and has received a passing grade from NVLAP.

c. Conclusions

Generally effective radiological controls were in place for the refueling outage, especially for the control of work in high and locked high radiation areas. However; radiological housekeeping was poor, some posted survey maps of the RCA were out of date, and two workers were observed in the RCA who were not aware of their surroundings. One violation of NRC requirements was also identified concerning workers failing to follow the RWP requirement to review the applicable survey maps of the RCA prior to entry.

R2 Status of RP&C Facilities and Equipment

R2.1 Calibration of Effluent/Process/Area/Accident Radiation Monitoring Systems (RMS)

a. Inspection Scope (84750)

The inspector reviewed the most recent radiological and electronic calibration results and calibration procedures for the effluent/process RMS. The inspector also held discussions with Health Physics and Instrumentation and Controls staff, and the RMS System Engineer.

The inspector utilized the following documents as a basis to determine whether the calibration procedures contained sufficient detail and guidance to verify conversion factors (calibration factors) and monitoring capability for the intended range (linearity):

- Regulatory Guide 1.21, "Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light Water Cooled Nuclear Power Plants, February 1979"

- Regulatory Guide 4.15, "Quality Assurance for Radiological Monitoring Programs (Normal Operations)- Effluent Streams and the Environment, February 1979"

- ANSI N42.18, 1980, "Specification and Performance of On-Site Instrumentation for Continuously Monitoring Radioactivity in Effluents"

- EPRI TR-102644, "Calibration of Radiation Monitors at Nuclear Power Plants, March 1994"

- Victoreen Installation, Operation, and Maintenance Instruction Manual Beta Scintillation Detectors Models 843-20, 843-20A, and 843-20B

- Victoreen Instruction Manual Gamma Scintillation Detector Model 843-30

The following Unit 1 RMS were reviewed.

- Liquid Waste Effluent
- Component Cooling Recirculation Spray Heat Exchange
- Process Vent Noble Gas
- Auxiliary Building Noble Gas
- Supplementary Leak Collection Noble Gas
- Containment Air
- Containment Purge

The following Unit 2 RMS were reviewed.

- Liquid Waste Effluent
- Ventilation System Noble Gas
- Elevated Release Noble Gas
- Decontamination Building Noble Gas
- Waste Gas Storage Vault
- Condensate Polishing Building Noble Gas
- Containment Purge Noble Gas

b. Observations and Findings

Electronic calibrations were appropriate. Linearity checking was appropriate. Good tracking and trending of the RMS was noted. The inspector noted that despite the age of RMS, reliability has been good. There were few open work orders at the time of the inspection.

The inspector did note that the licensee typically used supervisory discretion (permitted by procedure) rather than using the detailed guidance within the Health Physics Department procedure 5.11 for establishing a high voltage setting. Of the 22 channels of RMS reviewed, only 3 channels met EPRI guidance for establishing the operating high voltage. The inspector noted that the practice was contrary to existing standards and industry guidance documents.

RM-1RM-215A (Unit 1 containment particulate; Victoreen detector type 843-20A) operating voltage was established at 650 volts. Per licensee calibration data, the percent change over 50 volts at 650 volts on a operating voltage vs. count rate curve was 365%. The inspector noted that the vendor instruction manual directed the user to generate a plateau curve and noted that at 1100 volts the count rate should reach the lower end of the plateau. Contrary to the vendor instruction manual and the above noted guidance documents that operating high voltage be set on the plateau, the licensee established operating high voltage by changing high voltage to a point at which actual counts equalled expected counts with a National Institute of Standards and Technology (NIST) traceable source.

RM-1LW-104 (Unit 1 liquid waste effluent; Victoreen detector type 843-30) operating voltage was established at 450 volts. Per licensee calibration data, the percent change over 50 volts at 450 volts on a operating voltage vs. count rate curve was 133%. The inspector noted that the vendor instruction manual specifications for operating voltage were 500 to 1400 volts. The inspector also noted that the vendor manual recommended that the operating high voltage be established by generating a signal to noise ratio curve and setting high voltage to the peak value on the curve (this method is also described in EPRI TR-102644). Contrary to the vendor instruction manual and the above noted guidance documents, the licensee established operating high voltage by changing high voltage to a point at which actual counts equalled expected counts with a NIST traceable source.

TS 6.8.1.a requires, in part, that written procedures shall be established, implemented, and maintained covering the activities recommended in Appendix A of Regulatory Guide 1.33 (RG 1.33), Revision 2, February 1978. Appendix A of the RG 1.33, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors," describes typical procedures for the control of radioactivity, including procedures involving radiation monitoring systems.

Contrary to the above, the licensee failed to establish adequate RMS calibration instructions in regard to determining RMS operating high voltage. Specifically, operating high voltage was not established on a plateau for RM-1RM-215A (Unit 1 Containment Particulate) and RM-1LW-104 (Unit 1 Liquid Waste Effluent). This was contrary to vendor manual "Victoreen Installation, Operation, and Maintenance, Instruction Manual Beta Scintillation Detectors Models 843-20, 843-20A, and 843-20B" and "Victoreen Instructional Manual Gamma Scintillation Detectors Model 843-30" respectively; and was contrary to RMS calibration standards and industry guidance documents. This is a violation of NRC requirements **(VIO 50-334/97-08-05)**.

In reviewing as-found and as-left high voltages for the above noted RMS calibrations and a synopsis of similar data provided by the RMS Health Physicist, the inspector noted that typically there was little if any high voltage drift. In one case, a drift of 30 volts was noted. For this particular RMS, the operating high voltage had been set close to the plateau and, as a result, this relatively large drift in operating high voltage had very little impact on the accuracy of RMS output. While the technique used to establish operating high voltage was technically deficient, the inspector did not identify any case in which high voltage drift had led to error such that the validity of data provided in the annual effluent report was questionable. During the inspection and at the exit meeting, licensee representatives indicated that prior to a planned batch release a sample is taken, thereby providing a check on RMS operability.

The inspector questioned the licensee as to whether they could provide any information pertaining to new/refurbished detector failures. The Health Physics Manager informed the inspector that if BVPS identified a faulty detector, it was replaced; but, the failure cause may not be documented. This matter will be reviewed further **(IFI 50-334/97-08-06)**.

c. Conclusion

RMS reliability has generally been good. Electronic alignment and linearity checking were good. The inspector noted that the licensee had failed to implement industry guidance (EPRI TR-102644 and ANSI N42.18) which specifically direct that the operating voltage be set on a plateau and, in two cases, had failed to implement vendor manual instructions for establishing operating high voltage. The inspector concluded that this was a poor calibration practice which has the potential for leading to instrument error. Instrument error could impede or prevent an accurate assessment of public exposures and environmental impact in the case of an inadvertent release of radioactive materials.

R2.2 Air Cleaning Systems

a. Inspection Scope (84750)

The inspectors reviewed the licensee's most recent surveillance test results, including visual inspections, in-place High Efficiency Particulate Air (HEPA) leak tests, in-place charcoal leak tests, air capacity tests, pressure drop tests, and laboratory tests for the iodine collection efficiencies for the Supplementary Leak Collection and Release Systems (SLCRS).

b. Observations and Findings

All test results were within the licensee's acceptance criteria. No procedural inadequacies were noted. Unsatisfactory test results were analyzed and corrective actions were implemented in a timely manner. The inspectors noted that attention given to the air cleaning systems was good. System Engineers monitored and trended the performance of the air cleaning systems.

c. Conclusions

Those portions of the test program reviewed were well-implemented with strong monitoring and trending of air cleaning system performance parameters.

R5 Staff Training and Qualification in RP&C

a. Inspection Scope (83750)

The inspectors reviewed the qualifications of 23 contractor health physics technicians to ensure they were appropriately classified as junior or senior technicians. The records were selected by the inspectors at random.

b. Observations

The licensee hired 86 contractor health physics technicians (66 senior and 20 junior) in order to support the Unit 1 refueling outage. The inspectors selected 23 records at random and reviewed the licensee's calculations for technician experience. All calculations reviewed were determined to be appropriate, and in general, the inspectors determined that the licensee was conservative in reviewing technician qualifications.

c. Conclusions

The licensee appropriately classified contractor health physics technicians with regards to previous experience.

R7 Quality Assurance (QA) in RP&C Activities

a. Inspection Scope (84750)

The inspection consisted of: (1) review of the 1996 Quality Services Unit (QSU) audit of the Site Radiological Effluent and Environmental Monitoring Programs, (2) QSU surveillances and (3) self-assessments.

b. Observations and Findings

Audit team members included a technical specialist from another utility. The depth of the audit was good. The audit team identified several minor discrepancies and matters for enhancing the radioactive liquid and gaseous effluent control programs. No items were of regulatory significance.

Surveillances and self-assessments were also well-targeted and helped to augment the audit.

c. Conclusion

This program area was well implemented.

L1 Review of FSAR Commitments

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.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the results of the radiation protection and radioactive effluent control inspections to Mr. R. Vento on October 10, 1997. The results of the ISI program inspection were presented to Mr. S. Jain and Mr. R. LeGrand on October 24. The licensee acknowledged the findings presented. After further in-office review of information pertaining to the RMS calibration, the inspector concluded that a violation of NRC requirements had occurred.

The inspectors conducted an interim exit with Mr. S. Jain on November 10, 1997, to discuss the apparent violation documented in this report. The inspectors presented the remainder of the inspection results in a meeting with Mr. J. Cross and members of his staff at the conclusion of the inspection on November 21, 1997. The licensee acknowledged the findings presented with one exception.

The licensee disagreed with the NRC's position that venting the HHSI pumps immediately prior to surveillance test preconditioned the pumps. The licensee stated that the purpose of venting the suction lines on the HHSI pumps prior to surveillance testing was to ensure long term reliability of the pumps. The venting was not performed to create an enhanced test environment. The licensee stated that venting the pump would not change the environment such that it could be considered preconditioning.

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

The pre-decisional enforcement conference referred to in NRC Inspection Report 50-334 and 50-412/97-07 has been scheduled for December 10 at the NRC Region I office to discuss the apparent violation documented in that report and URI 50-334 and 412/97-08-03 of this report.

PARTIAL LIST OF PERSONS CONTACTED

DLC

J. Cross, President, Generation Group
R. LeGrand, Vice President, Nuclear Operations/Plant Manager
S. Jain, Vice President, Nuclear Services
M. Pergar, Acting Manager, Quality Services Unit
B. Tuite, General Manager, Nuclear Operations
R. Hansen, General Manager, Maintenance Programs Unit
R. Vento, Manager, Health Physics
D. Orndorf, Manager, Chemistry
F. Curl, Manager, Nuclear Construction
J. Matsko, Manager, Outage Management Department
T. Lutkehaus, Manager, Maintenance Planning & Administration
T. McGhee, Coordinator, Onsite Safety Committee
J. Macdonald, Manager, System & Performance Engineering
K. Beatty, General Manager, Nuclear Support Unit
J. Arias, Director, Safety & Licensing
W. Kline, Manager, Nuclear Engineering Department
R. Brosi, Manager, Management Services
O. Arredondo, Manager, Nuclear Procurement

NRC

D. Kern, SRI
G. Dentel, RI
F. Lyon, RI

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 73753:	Inservice Inspection
IP 83750:	Occupational Exposure
IP 84750:	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
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

ITEMS OPENED, CLOSED AND DISCUSSED

Opened

50-412/97-08-03	URI	Test Control - High Head Safety Injection Pumps (Section E2.1)
50-334/97-08-04	VIO	Workers were Unaware of Radiological Conditions in their Work and Transit Areas in the RCA (Section R1)
50-334/97-08-05	VIO	Failure to Calibrate RMS in Accordance with Proper Procedures (Section R2.1)
50-334/97-08-06	IFI	Documentation of RMS Detector Failures (Section R2.1)

Opened/Closed

50-334/97-08-01	NCV	Mispositioning of RCCA in the SFP (Section O1.2)
50-334 and 312/97-08-02	NCV	Implementation of the Retired Equipment Program (Section O3.1)

Closed

50-334/96-012	LER	Entry into Technical Specification 3.0.3 Due to Isolation of Control Room Emergency Breathing Air Pressurization System (Section O8.1)
50-334/97-004-01	LER	Failure to Test Post DBA Hydrogen Control System Recombiners in Accordance With Technical Specifications (Section O8.2)
50-334/97-032	LER	EDG Automatic Start During Bus Transfer from Unit to System Station Transformer (Section O8.3)
50-334 and 412/97-07-04	URI	Adequacy of the High Head Safety Injection Pump Surveillance Tests to Ensure Operability (Section E2.1)
50-334/96-05-02	VIO	Inadequate Calibration for UT examinations (Section E8.2)
50-334 and 412/97-07-01	URI	Implementation of the Retired Equipment Program (Section O3.1)

LIST OF ACRONYMS USED

1R12	Unit 1 12th Refueling Outage
AFW	Auxiliary Feedwater Pump
ALARA	As Low As is Reasonably Achievable
ANII	Authorized Nuclear Inservice Inspector
AOP	Abnormal Operating Procedure
AVB	Anti-Vibration Bar
BVPS	Beaver Valley Power Station
CR	Condition Report
CREBAPS	Control Room Emergency Breathing Air Pressurization System
DCP	Design Change Package
DLC	Duquesne Light Company
EDG	Emergency Diesel Generator
EEI	Escalated Enforcement Issue
EOP	Emergency Operating Procedure
ESF	Engineered Safety Feature
HEPA	High efficiency Particulate Air
HHSI	High Head Safety Injection
I&C	Instrumentation and Controls
ISI	Inservice Inspection
IST	Inservice Surveillance Test
LER	Licensee Event Report
MPFF	Maintenance Preventable Functional Failures
MSP	Maintenance Surveillance Procedure
MT	Magnetic Particulate
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NIS	Nuclear Instrumentation System
NIST	National Institute of Standards and Technology
NPDAPS	Nuclear Power Division Administrative Procedure
NVLAP	Nuclear Voluntary Laboratory Accreditation Program
ODCM	Offsite Dose Calculation Manual
ODSCC	Outside Diameter Stress Corrosion Cracking
OST	Operational Surveillance Test
PCE	Personnel Contamination Event
PDR	Public Document Room
PMP	Preventive Maintenance Procedure
PT	Liquid Penetrant
PWSCC	Primary Water Stress Corrosion Cracking
QA	Quality Assurance
QC	Quality Control
QSU	Quality Services Unit
RCA	Radiological Controlled Area
RCCA	Rod Cluster Control Assembly
RMS	Radiation Monitoring System
RP&C	Radiological Protection and Chemistry
RTS	Reactor Trip System

RWP	Radiological Work Permit
SFP	Spent Fuel Pool
SG	Steam Generator
SLCRS	Supplementary Leak Collection and Release System
SSPS	Solid State Protection System
TER	Technical Evaluation Report
TS	Technical Specification
TSP	Tube Support Plate
TTS	Tubesheet
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Examination
VIO	Violation
VT	Visual Examination