January 31, 2002

Mr. L. W. Myers
Senior Vice President
Post Office Box 4
FirstEnergy Nuclear Operating Company
Shippingport, Pennsylvania 15077

SUBJECT: BEAVER VALLEY POWER STATION - NRC INSPECTION REPORT 50-334/01-10, 50-412/01-10

Dear Mr. Myers:

On December 29, 2001, the NRC completed an inspection at your Beaver Valley Units 1 & 2. The enclosed report documents the inspection findings which were discussed on January 11, 2002, with you and members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the inspectors identified four issues of very low safety significance (Green). One issue was determined to involve a violation of NRC requirements. However, because of its low safety significance and because it has been entered into your corrective action program, the NRC is treating this issue as a Non-Cited violation, in accordance with Section VI.A of the NRC's Enforcement Policy. If you deny this Non-Cited violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Beaver Valley facility.

Immediately following the terrorist attacks on the World Trade Center and the Pentagon, the NRC issued an advisory recommending that nuclear power plant licensees go to the highest level of security, and all promptly did so. With continued uncertainty about the possibility of additional terrorist activities, the Nation's nuclear power plants remain at the highest level of security and the NRC continues to monitor the situation. This advisory was followed by additional advisories, and although the specific actions are not releasable to the public, they generally include increased patrols, augmented security forces and capabilities, additional security posts, heightened coordination with law enforcement and military authorities, and more limited access of personnel and vehicles to the sites. The NRC has conducted various audits of your response to these advisories and your ability to respond to terrorist attacks with the capabilities of the current design basis threat (DBT). From these audits, the NRC has concluded that your security program is adequate at this time.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm.html (the Public Electronic Reading Room).

Sincerely,

/RA Curtis J. Cowgill f/

John F. Rogge, Chief
Projects Branch No. 7
Division of Reactor Projects

Docket Nos.: 50-334, 50-412
License Nos: DPR-66, NPF-73

Enclosure: Inspection Report 50-334/01-10; 50-412/01-10
Attachment: Supplemental Information

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REGION I

Docket Nos.	50-334, 50-412
License Nos.	DPR-66, NPF-73
Report Nos.	50-334/01-10, 50-412/01-10
Licensee:	FirstEnergy Nuclear Operating Company
Facility:	Beaver Valley Power Station, Units 1 and 2
Location:	Post Office Box 4 Shippingport, PA 15077
Dates:	November 11 - December 29, 2001
Inspectors:	D. Kern, Senior Resident Inspector G. Wertz, Resident Inspector J. Caruso, Senior Operator Examiner G. Cranston, Reactor Inspector J. Herrera, Project Engineer A. Lohmeier, Reactor Inspector J. McFadden, Health Physics Inspector N. Perry, Senior Project Engineer L. Prividy, Senior Reactor Inspector
Approved by:	J. Rogge, Chief, Projects Branch 7 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000334-01-010, IR 05000412-01-10, on 11/11 - 12/29/2001; FirstEnergy Nuclear Operating Company; Beaver Valley Power Station; Units 1 & 2. Maintenance Risk Assessment and Emergent Work Control, Personnel Performance during Nonroutine Plant Evolutions, and Event Follow-up.

The inspection was conducted by resident inspectors, reactor systems engineers, an operator licensing examiner, a regional health physics inspector, and regional projects inspectors. The inspection identified four Green findings, one of which was a Non-Cited violation. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609 "Significance Determination Process" (SDP). Findings for which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violation. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website http://www.nrc.gov/NRR/OVERSIGHT/index.html.

A. Inspector Identified Findings

Cornerstone: Initiating Events

- **Green** The inspectors identified a Non-Cited Violation of Technical Specification 6.8.1 for failure to properly perform maintenance which can affect the performance of safety-related equipment in accordance with written procedures or instructions. On several occasions, safety-related work activities were not properly controlled, resulting in unexpected control room alarms and indications. In one instance, Unit 1 operators responded by manually tripping the reactor, while the reactor was subcritical. In another instance, Unit 1 automatic reactor coolant system pressure control was disabled, and operators had to manually establish pressure control pending system restoration. Human performance deficiencies, such as poor communications between operators and technicians, were the cause of each event. In each case, the performance deficiency caused or increased the likelihood of an initiating event.

  The safety significance of this finding was very low (Green) because the performance deficiency did not cause any accident mitigation equipment or functions to be unavailable. (Section 1R13)

- **Green** The inspectors determined that corrective actions to a June 22, 2001, Unit 1 loss of instrument air (LOIA) reactor trip were not effectively implemented. Consequently, failure to identify and perform manufacturer recommended preventive maintenance tasks for the 'B' station air compressor (2SAS-C21B) loading/throttle mechanism was the direct cause of two subsequent Unit 2 LOIA events (November and December 2001).

  The safety significance of this finding was very low (Green) because the performance deficiency did not cause any accident mitigation equipment or functions to be unavailable. (Section 1R14)

- **Green** The inspectors determined that inadequate work planning and maintenance technician performance errors caused a Unit 1 LOIA and manual reactor trip on December 7, 2001. The equipment clearance, posted to completely de-energize the 'B' air compressor prior to beginning work failed to identify an energized contact which connected the 'A' and 'B' air compressors. Additionally, electricians used incorrect tools and failed to adequately perform safety checks to verify the 'B' air compressor circuitry was completely deenergized. The event review team also identified a latent vulnerability of the air system which had not been recognized following a similar reactor trip on June 22, 2001. A modification to the air dryer system several years ago, increased air system usage beyond the capacity of the backup diesel powered air compressor. As a result, although operators started the diesel air compressor promptly on December 7, they were unable to recover instrument air pressure prior to the reactor trip. The LOIA increased the likelihood that mitigation equipment (specifically the power conversion system, auxiliary feedwater bleed path, and primary heat removal feed/bleed) would not be available. The issue was determined to effect the initiating event and barrier integrity cornerstones.

  The safety significance of this event was very low (Green) because the performance deficiency did not cause any accident mitigation equipment or functions to be unavailable. (Section 4OA3.1)

- **Green** The inspectors determined that failure to identify and perform preventive maintenance tasks for instrument air dryer 1IA-D-1 in accordance with manufacturer recommendations was the root cause of the June 22, 2001, Unit 1 LOIA and subsequent manual reactor trip. The LOIA increased the likelihood that mitigation equipment (specifically the power conversion system, auxiliary feedwater bleed path, and primary heat removal feed/bleed) would not be available. The LOIA and loss of component cooling water to the reactor coolant pumps also increased the potential for a reactor coolant system leak. The issue was determined to effect the initiating event and barrier integrity cornerstones.

  The safety significance of this finding was very low (Green) because the performance deficiency did not cause any accident mitigation equipment or functions to be unavailable. (Section 4OA3.2)

B. Licensee Identified Violations

None were identified.

Report Details

SUMMARY OF PLANT STATUS: Unit 1 began this inspection period at 100 percent power. On December 7, the 'C' main steam isolation valve (MSIV) began to close due to a maintenance error which caused a loss of instrument air (LOIA). Operators manually tripped the reactor, as required by procedures (Section 4OA3.1). Following repairs to the station air system compressors, the unit was synchronized to the electrical distribution grid on December 10. The unit achieved 100 percent power on December 11 and remained at full power through the end of the inspection period.

Unit 2 operated at 100 percent power throughout the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors reviewed the station's cold weather protection adequacy in accordance with the following operating surveillance tests (OST) and operating manual (OM) procedure:

- 1OST-45.11, "Cold Weather Protection Verification", Rev. 15
- 2OST-45.11, "Cold Weather Protection Verification", Rev. 14
- 2OM-45D.3.C, "Power Supply and Control Switch List", Rev. 7

The inspectors reviewed the outstanding work deficiencies noted in the cold weather protection OSTs and verified that they were of minor significance and/or properly captured in the corrective maintenance program. The operating manual was reviewed to verify that electrical breakers associated with heat tracing were properly positioned. Work orders (WO) and condition reports (CR) written to correct deficiencies identified during the cold weather protection procedure inspection were also reviewed. The inspectors performed a walkdown of selected Unit 1 and Unit 2 safety-related heat tracing control panels and heat trace for the Unit 2 refueling water storage tank (RWST) piping. The inspectors observed that a temporary heater and enclosure had been constructed around the RWST quench spray piping running up along the side of the RWST, to provide freeze protection pending completion of repair/replacement of defective heat trace. The inspectors interviewed control room operators to assess their understanding of cold weather protection for equipment and associated alarms.

b. Findings

No findings of significance were identified.

1R02 Evaluations of Changes, Tests, or Experiments

a. Inspection Scope

The inspectors reviewed safety evaluations associated with mitigating systems and barrier integrity cornerstones to verify that changes to the facility or procedures as described in the Updated Final Safety Analysis Report (UFSAR) were reviewed and documented in accordance with 10 Code of Federal Regulations (CFR) 50.59. Safety evaluations were selected based upon the safety significance of the changes and the risk to structures, systems, and components.

The inspectors also reviewed applicability reviews (10 CFR 50.59 safety screens) for changes, tests, and experiments for which the licensee determined that a safety evaluation was not required. This review was performed to verify that the licensees' threshold for performing safety evaluations was consistent with 10 CFR 50.59.

Finally, the inspectors reviewed a sample of CRs documenting problems identified by the licensee in their corrective action program related to safety evaluations to verify the effectiveness of corrective actions.

A listing of the 10 CFR 50.59 safety evaluations, safety screens, and CRs reviewed is provided in Attachment 1.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments

a. Inspection Scope

The inspectors performed a partial system walkdown of the Unit 2 Service Water (SW) system. The inspectors reviewed the system alignment to verify that it was aligned properly as described in OM Figure 30-1. The SW system was selected due to one of the pumps being unavailable due to planned maintenance.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors reviewed the Unit 1 Updated Fire Protection Appendix 'R' Review, Rev. 16, and the Unit 2 Fire Protection Safe Shutdown Report, Addendum 18, and identified the following risk significant areas:

- Unit 1 Cable Spreading Room (Fire Area CS-1)

- Unit 2 Cable Vault and Rod Control Area (Fire Area CV-1)
- Unit 2 Cable Vault and Rod Control Area (Fire Area CV-2)
- Unit 2 Emergency Diesel Generator Building (Fire Area DG-1)

The inspectors reviewed the fire protection conditions of the above listed areas in accordance with the criteria delineated in Nuclear Power Division Administrative Procedure (NPDAP) 3.5, “Fire Protection,” Rev. 15. Control of transient combustibles, material condition of fire protection equipment, and the adequacy of any fire protection impairments and compensatory measures were included in these plant specific reviews.

b. Findings

No findings of significance were identified.

R11 Licensed Operator Requalification

a. Inspection Scope

An in office review was conducted of licensee requalification exam results for the biennial testing cycle. The inspection assessed whether pass rates were consistent with the guidance of NUREG-1021, “Operator Licensing Examination Standards for Power Reactors,” Rev. 8, and NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP)”.

The inspectors verified for Beaver Valley Unit 1 that:

- Crew pass rate on the simulator test was greater than 80 percent. (Pass rate was 90 percent.)
- Individual pass rate on the simulator test was greater than or equal to 80 percent. (Pass rate was 100 percent)
- Individual pass rate on the job performance measures (JPMs) walk-through was greater than or equal to 80 percent. (Pass rate was 100 percent)
- Individual pass rate on the written exam was greater than or equal to 80 percent. (Pass rate was 97 percent.)
- Individual pass rate for all portions of the exam was greater than or equal to 75 percent. (99 percent of the individuals passed all portions of the exam.)

The inspector verified for Beaver Valley Unit 2 that:

- Crew pass rate on the simulator test was greater than 80 percent. (Pass rate was 90 percent.)
- Individual pass rate on the simulator test was greater than or equal to 80 percent. (Pass rate was 100 percent)
- Individual pass rate on the JPMs walk-through was greater than or equal to 80 percent. (Pass rate was 96 percent.)

- Individual pass rate on the written exam was greater than or equal to 80 percent. (Pass rate was 97 percent.)

- Individual pass rate for all portions of the exam was greater than or equal to 75 percent. (98 percent of the individuals passed all portions of the exam.)

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors evaluated Maintenance Rule (MR) implementation for systems listed below. Specific attributes reviewed included MR scoping, characterization of failed structures, systems, and components (SSCs), MR risk categorization of SSCs, SSC performance criteria or goals, and appropriateness of corrective actions. The inspectors verified that the issues were addressed as required by 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance of Nuclear Power Plants,” and System and Performance Engineering Administrative Manual 3.2, “Maintenance Rule Program Administration,” Rev. 3.

- The Unit 2 condensate system health report and improvement plan for appropriateness of classification and planned improvements were evaluated. The system was designated as a MR (a)(2) system. Additionally, the general condition of the system was visually inspected.
- The Unit 2 SW system health report and improvement plan were evaluated for appropriateness of classification, planned improvements, and the System Engineer Input to MR Periodic Assessment. The system was designated as a MR (a)(1) system. Additionally, the general condition of the system was visually inspected.
- The Unit 1 ‘B’ river water (RW) pump and motor were replaced with an upgraded design of motor and pump during this inspection period. The replacement was a corrective action to improve the overall availability, reliability, and flow performance of the pump. The system was designated as a MR (a)(2) system. Additionally, the general condition of the system was visually inspected.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the scheduling and control of maintenance activities in order to evaluate the effect on plant risk. This review was against criteria contained in NPDAP 7.12, “Non-outage Planning, Scheduling, and Risk Assessment,” Rev. 11. The inspectors reviewed routine planned maintenance and emergent work for the following equipment removed from service:

- Emergent repair of the ‘C’ steam generator atmospheric steam dump valve, 2SVS-PCV101C, following a control power supply failure on November 26. Control room operators evaluated the risk impact with the probabilistic risk assessment engineer and delayed scheduled maintenance on 2SVS-PCV101B pending repair of the ‘C’ steam dump valve. Control room operators assessed the degraded condition and determined that the valve could be manually operated if needed. Operators determined that the License Requirements Manual permitted continued operation for up to 21 days in this condition. The inspectors reviewed procedure 2OM-21.4.J, “Manual Handpump Operation of [2SVS*PCV101A, B, C] Atmospheric Steam Dump,” Rev. 2, and verified that the control room operators were cognizant of the required manual valve operator actions. The power supply failure was accurately captured in CR 01-7690.
- Planned maintenance to install an upgraded Unit 1 ‘B’ RW pump and to overhaul the Unit 1 ‘B’ high-head safety injection (HHSI) pump.
- A series of planned and emergent maintenance activities which required close communications between operators, engineers, and instrumentation and control (I&C) technicians. Work activities included Unit 1 control rod drop testing, control rod position indication calibration verification, and repair of pressurizer level transmitter LT-1RC-461.

b. Findings

Human Performance and Communication Errors Cause Unplanned Initiating Events

The inspectors identified a Non-Cited Violation (NCV) of Technical Specification (TS) 6.8.1 for failure to properly perform maintenance, which can affect the performance of safety-related equipment, in accordance with written procedures or instructions. On several occasions, safety-related work activities were not properly controlled, resulting in unexpected control room alarms and indications. In one instance, Unit 1 operators responded by manually tripping the reactor, while the reactor was subcritical. In another instance, Unit 1 automatic reactor coolant system (RCS) pressure control was disabled, and operators had to manually establish pressure control pending system restoration. Human performance deficiencies contributed substantially to the cause of each event. Unplanned challenges to plant configuration can increase the likelihood of initiating events and increase plant risk. The safety significance of this finding was very low (Green) because the performance deficiency did not cause any accident mitigation equipment or functions to be unavailable.

On October 6, I&C technicians, engineers, and Unit 1 control room operators were performing 1Beaver Valley Test (BVT)-1.1.1, “Control Rod Drop Test,” Rev. 1, and 1BVT-1.1.7, “Rod Position Indication (RPI) System Calibration Verification,” Rev. 6, in preparation for reactor startup. Following shift turnover, these tests continued. However, the new crew of engineers and technicians did not confirm the communications protocols for the tests, which had been established during the previous shift. An engineer skipped a procedural step to inform the reactor operator that shutdown bank ‘B’ position indication would be lost during the next step. When technicians performed the next procedural step to open the applicable knife switches in the control cabinet, control room operators observed indications of two dropped control rods (RPI was zero steps and rod bottom lights were lit). The operators manually tripped the reactor as directed by 1OM-

53C.4.1.1.8, “Rod Inoperability,” Rev. 0. The licensee concluded that the cause of the unplanned reactor trip was inadequate procedural compliance.

On November 19, I&C technicians were inside the Unit 1 containment attempting to isolate a leak which caused RCS pressurizer level transmitter LT-1RC-461 to indicate inaccurately. Administrative Procedure 1/2-ADM-0803, “Processing a Work Order,” Rev. 0, requires the work activity to be performed in accordance with the instructions and procedures documented in the work package. Work instructions and boundaries, identified in the work package had been discussed during an Infrequently Performed Test or Evolution briefing before the work activity began. Communications between the work crew and a control room phone talker (an I&C technician) were established. The work crew identified a leak near pressurizer pressure transmitter PT-1RC-445, which was outside of the work boundary identified in the work instructions. They requested permission to isolate PT-1RC-445. The control room phone talker had relocated to the computer room following the preevolution brief. The phone talker gave the work crew permission to isolate PT-1RC-445 and headed for the control room to inform the reactor operator. The work crew isolated PT-1RC-445, causing an unexpected pressurizer low pressure alarm and loss of automatic RCS pressure control before the phone talker arrived in the control room. The phone talker did not have authority to direct repositioning primary plant valves which were outside the work activity boundary, but had done so without first informing the control room staff. The cause of the unplanned loss of automatic RCS pressure control was noncompliance with work instructions and poor communications.

The issue had a credible impact on safety in that failure to properly implement maintenance on safety-related components can cause unplanned initiating events (i.e., reactor trip, RCS pressure transient, or inadvertent engineered safety-feature actuation), which increase plant risk. In this case, PT-1RC-445 provided only a control function, and did not affect accident mitigating functions. The inspectors reviewed both occurrences in accordance with Phase 1 of the SDP and determined that the safety significance was very low (Green). In each case, the performance deficiency caused or increased the likelihood of an initiating event, but did not cause mitigation equipment to be inoperable.

TS 6.8.1 requires that written procedures be properly implemented covering the activities referenced in Appendix “A” of Regulatory Guide 1.33, Rev. 2, February 1978. Appendix “A” of Regulatory Guide 1.33, specifies that maintenance that can affect the performance of safety-related equipment be preplanned and performed in accordance with written procedures or instructions. Contrary to these requirements, engineers and technicians failed to implement control rod testing in accordance with 1BVT-1.1.1 and pressurizer level transmitter corrective maintenance in accordance with 1/2-ADM-0803. This violation of TS 6.8.1 is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 50-334/01-10-01)**. This violation was entered into the licensee’s corrective action program as CRs 01-6745, 01-7634, 01-7681, and 01-7760.

1R14 <u>Personnel Performance During Nonroutine Plant Evolutions</u>

a. <u>Inspection Scope</u>

The inspectors reviewed human performance during the following nonroutine plant evolution, to determine whether personnel performance caused unnecessary plant risk or challenges to reactor safety. Additionally, the inspectors evaluated the associated procedure use and causal assessment to determine whether station procedures were properly implemented.

- On December 11, 2001, Unit 2 control room operators received low station air pressure and low instrument air pressure alarms. The ‘B’ station air compressor had failed to maintain load. Operators promptly implemented procedure 2OM-53C.4.2.34.1, “Loss of Station Instrument Air,” Rev. 5, which included bypassing the instrument air dryer locally. The ‘A’ station air compressor automatically started and system air pressure recovered without further equipment challenges.

b. <u>Findings</u>

The inspectors determined that corrective actions to a June 22, 2001, Unit 1 LOIA reactor trip (Section 4OA3.2) were not effectively implemented. Consequently, failure to identify and perform manufacturer recommended PM tasks for the ‘B’ station air compressor (2SAS-C21B) loading/throttle mechanism was the direct cause of two subsequent Unit 2 LOIA challenges (November and December 2001). The safety significance of this finding was very low (Green) because the performance deficiency did not cause any accident mitigation equipment or functions to be unavailable.

On November 8, 2001, following completion of various compressor PMs, the ‘B’ station air compressor loading/throttle mechanism failed. The compressor unloaded and caused a low pressure condition on the station and instrument air systems. Operators implemented 2OM-53C.4.2.34.1 and recovered instrument air pressure sufficiently to avoid a plant transient. Mechanics subsequently determined that a degraded unloader piston rolling diaphragm caused the failure. A replacement PM existed for this diaphragm, but the periodicity was every 2 years instead of annually, as recommended by the vendor for this type of application. On December 11, the loading/throttle mechanism failed again causing a repeat event. This time mechanics determined that excessive wear caused a retaining clip on the throttle shaft to release, causing the loading/throttle mechanism to fail. The inspectors noted that the vendor technical manual recommended annual inspection of the loading/throttle mechanism be performed by the manufacturer’s service representative. Although mechanics performed a periodic inspection PM, the work scope did not include the retaining clip. A manufacturer representative provided oversight during repairs following the December 11 failure. He confirmed that the existing inspection PM scope failed to include numerous critical equipment parts. The manufacturer representative recommended upgrading the existing PM to become an annual loading/throttle mechanism inspection and rebuild, consistent with manufacturer service standards.

Corrective actions to the June 22, 2001, Unit 1 reactor trip included extent of condition reviews to verify appropriate PMs were identified and performed on station air compressors for both units. Although that corrective action was complete, station personnel failed to identify all of the appropriate manufacturer recommended PMs for the loading/throttle mechanism. A manufacturer representative informed them of the recommended PMs during a site visit following the December 11 LOIA event. The inspectors subsequently reviewed the associated air compressor technical manual and confirmed that some PMs were not being performed as recommended in the technical manual. Engineers initiated corrective action to reassess PM scope for the Unit 1 and Unit 2 station air compressors. This action was in progress at the close of this inspection period.

The ineffective corrective action issue had a credible impact on safety, because it could cause a reactor trip and increase overall plant core damage frequency as described in Sections 4OA3.1 and 4OA3.2. The resulting LOIA increased the likelihood that mitigation equipment (specifically the power conversion system, auxiliary feedwater (AFW) bleed path, and primary heat removal feed/bleed) would not be available and increased the likelihood of a reactor trip. Therefore, a Phase 2 SDP evaluation was required. After discussions with the NRC Region I senior risk analyst, the inspectors determined that modeling inconsistencies in the Unit 2 specific SDP existed for the LOIA event. The Unit 1 SDP more accurately models the LOIA event. Therefore, using Tables 1 and 2 of the Beaver Valley Unit 1 Risk Informed Inspection Notebook (Unit 1 specific SDP), the inspectors determined the station instrument air system was effected and the LOIA event scenario applied. The exposure time of the PM performance deficiency was greater than 30 days. The inspectors evaluated the four accident sequences listed in Table 3.13 for the LOIA initiating event. Applying the result to the risk significance estimation matrix shown in Table 4, the inspectors determined the risk associated with this finding was GREEN. Based on this Phase 2 SDP analysis, the inspectors determined the event had very low safety significance and was a GREEN finding (CR 01-8030). The issue was not a violation of regulatory requirements because instrument air is a nonsafety-related system.

1R15 <u>Operability Evaluations</u>

a. <u>Inspection Scope</u>

The inspectors reviewed operability evaluations in order to determine that proper operability justifications were performed for the following items. In addition, where a component was determined to be inoperable, the inspectors verified the TS limiting condition for operation implications were properly addressed.

- A through wall leak of service water system (SWS) piping (line 2-SWS-003-182-3), which supplies service water to the 'B' train of the charging pump lubricating oil coolers, was evaluated by system and structural engineers in accordance with System Performance Engineering Administrative Procedure, (SPEAP) 1.13, "Preparing System/Component Performance Evaluations," Rev. 2. The leak rate, as documented in CR 01-7282 on November 2 and monitored by plant operators, remained stable at approximately 2 drops per minute through a very small (pinhole) opening. Non-destructive evaluation (NDE) engineers tested the piping around the pinhole leak and determined that the pinhole was an isolated leak and the remaining piping area met the minimum required wall thickness of 0.130 inches. The inspectors observed the leak, reviewed the contingency measures for mitigating and monitoring the leakage rate by plant operators, and discussed the NDE test results with cognizant engineers in order to assess the structural integrity of the line and evaluate the potential effects that a leakage increase would have on surrounding equipment.

- The Unit 1 ‘B’ and ‘C’ HHSI pump discharge check valves (1CH-23 and 1CH-24) degraded and demonstrated back leakage. This leakage could divert flow from the running pump and challenge HHSI system operability. On November 20, 2001, leakage past 1CH-23 increased from approximately 1 gallon per minute (gpm) to 5.5 gpm. Repairs to 1CH-23 in early 2000 were unsuccessful. Repair activities for both valves were repeatedly deferred in 2001. The inspectors reviewed basis for continued operation 1-00-006, “1CH-23 Back-Leakage,” Rev. 0; engineering memorandum 201231, “SPEAP 1.13 Engineering Evaluation for 1CH-23 Leakage,” Rev. 0; and CR 01-7788. 1CH-23 was repaired at the close of this inspection period and awaited post-maintenance testing (PMT).

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed the cumulative effects of the Unit 1 and Unit 2 operator work-arounds (including control room deficiencies) to determine whether the likelihood of an initiating event was increased, mitigating system functionality was effected, or whether the operator’s ability to implement abnormal or emergency operating procedure actions was effected. The inspectors also performed equipment walk-downs and record reviews to verify that, when appropriate, degraded plant conditions were identified and managed as required by Operations Management Desktop Guide (OMDG) 002, “Operations Work-Arounds/Control Room Deficiencies,” Rev. 5. The inspectors discussed two repetitive material deficiencies (Unit 1 automatic rod control and Unit 2 plant computer system) with nuclear shift supervisors who initiated appropriate actions to add these to the operator work-around list.

The inspectors noted that several Unit 1 operator work-arounds had not been corrected during the last refueling outage. OMDG-002 requires that all operator work-arounds be fixed or reviewed by the Plant General Manager prior to restart from a refueling outage. The inspectors reviewed the work-scope for the upcoming Unit 2 9^{th} refueling outage to determine whether corrective actions to resolve operator work-arounds were properly scheduled as recommended in OMDG-002. The inspectors discussed discrepancies with the Operator Work-Around Coordinator and the Plant General Manager, who initiated appropriate corrective action.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors selected and reviewed permanent modifications of Beaver Valley. Permanent plant modifications were selected from design changes that were completed at Beaver Valley since January 2000. The Unit 1 'B' RW pump replacement modification, which was partially completed, was also reviewed. The inspectors observed the installation activities for the 'B' RW pump. The group of modifications selected was based on risk insights from the Beaver Valley probabilistic risk assessment and impact on the reactor safety cornerstones. The modifications selected included complementary inspectable areas under the reactor safety cornerstones of initiating events, mitigation systems, and barrier integrity. The modifications included safety-related piping/components, safety-related electrical power systems and changes to plant operating procedures. Review of selected portions of the modification packages included the safety evaluation screening forms, 10 CFR 50.59 safety evaluations, design calculations, set point changes, and results of post-modification testing. Where appropriate, the inspectors discussed the scope and extent of the modifications, technical factors associated with the changes, and implementation of the changes with the responsible engineering personnel. A listing of the modifications reviewed is provided in Attachment 1.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed and/or observed several PMTs to ensure: 1) the PMT was appropriate for the scope of the maintenance work completed; 2) the acceptance criteria were clear and demonstrated operability of the component; and 3) the PMT was performed in accordance with procedures. The following PMTs were observed:

- RCS pressurizer level channel LT-1RC-461 failed the TS channel functional check surveillance test on November 19 after trending up for several days. Control room operators properly complied with the action statement of TS 3.3.1.1, and placed the associated channel bi-stables in the tripped condition. I&C technicians, aided by computer trend data, diagnosed the pressurizer level channel problem. Containment entries were made on November 19, 20, and 21, in order to identify and repair leaks on the reference leg of the level transmitter and restore the level indication. The inspectors reviewed the maintenance and PMT performed in accordance with the criteria listed in WO 01-022896-000.
- 2OST-30.2, "Service Water Pump [2SWS*P21A] Test," Rev. 21, following maintenance to the motor. The pump was satisfactorily tested in accordance with the above OST on November 16. The inspectors reviewed temporary change notice (TCN) 01-00338, which revised vibration limits in 2OST-30.2, against the criteria listed in "Beaver Valley Inservice Testing Program for Pumps and Valves," Rev. 3. The TCN adequately resolved a motor vibration concern identified in CR 01-7542.
- 2OST-47.3B, "Containment Penetration and American Society of Mechanical Engineers (ASME) Section XI Valve Test," Rev. 25, following emergent

maintenance to replace a failed power supply on the ‘C’ steam generator atmospheric steam dump valve, 2SVS-PCV101C. The valve was satisfactorily stroke tested in accordance with the requirements of 2OST-47.3B.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed and reviewed the following OSTs, concentrating on verification of the adequacy of the test to demonstrate the operability of the required system or component safety function.

- 1OST-11.1, “Safety Injection Pump Test -[1SI-P-1A],” Rev. 12. The inspectors noted that the pump differential pressure was near the specification limit (low) and was appropriately documented in CR 01-7687 by control room operators.
- 1OST-30.3, “Reactor River Water Pump 1B Test,” Rev. 26, following installation of a new RW pump. Operators properly documented a human error which inadvertently left the ‘B’ RW train inoperable for 3 hours following this test (CR 01-8324).
- 2OST-11.1, “Low Head Safety Injection Pump [2SIS*P21A] Test,” Rev. 17.

b. Findings

No findings of significance were identified.

Emergency Preparedness (EP)

EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed an emergency event training evolution conducted at the Unit 2 control room simulator to evaluate emergency procedure implementation, event classification, event notification, and protective action recommendation development. The event scenario involved multiple safety-related component failures and plant conditions warranting a simulated Alert event declaration. The licensee counted this training evolution for evaluation of Emergency Preparedness Drill/Exercise Performance (DEP) Indicators. The inspectors observed the drill critique to determine whether the licensee critically evaluated drill performance to identify deficiencies and weaknesses. The inspectors reviewed the event notification forms and DEP indicator results during this period to verify the DEP performance indicators were properly evaluated consistent with Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Rev. 1. Additional documents used for this inspection activity included:

- "Unit 2 Annual Exam Drill #33," Rev. 0
- Abnormal Operating Procedure 2.51.1, "Emergency Shutdown," Rev 9
- Emergency Operating Procedure (EOP) E-0, "Reactor Trip or Safety Injection," Rev. 1
- EOP E-3, "Steam Generator Tube Rupture," Rev. 1
- Emergency Plan Implementing Procedure (EPIP) IP 1.1, "Notifications," Rev. 27
- EPIP I-1a, "Recognition and Classification of Emergency Conditions," Rev. 1
- Emergency Preparedness -16, "NRC Emergency Preparedness Performance Indicator Instructions," Rev. 3

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS3 Radiation Monitoring Instrumentation

a. Inspection Scope

The inspectors reviewed the effectiveness of health physics instrumentation, installed radiation monitoring instrumentation, and the program to provide self-contained breathing apparatus (SCBA) to occupational workers.

The inspectors reviewed the program for health physics instrumentation and for installed radiation monitoring instrumentation to determine the accuracy and operability of the instrumentation.

During plant tours, the inspectors reviewed field instrumentation used by health physics technicians and plant workers to measure radioactivity and radiation levels, including portable field survey instruments, hand-held contamination frisking instruments, and continuous air monitors. The inspectors conducted a review of the instruments observed in the toured areas, specifically verification of current calibration, of appropriate source checks, and of proper function. The inspectors evaluated various calibration records and the following procedures and documents for regulatory compliance and adequacy.

- Radiological Instrumentation Procedure (RIP) 3.1, "Count rate meter - model E-140 or E-140N/HP-210 or HP-260," Rev. 1
- RIP 3.13, "Alpha survey meter - model ASP-1/43-2," Rev. 2
- RIP 3.5, "Teletector 6112 survey meter," Rev. 3
- RIP 4.6, "Xetex model 503A teledose telemetry system," Rev. 1
- RIP 5.2, "Smart radiation monitor (SRM-100)," Rev. 2
- RIP 5.23, "Canberra Genie AXP counting systems," Rev. 0
- CM 5.24A, "Efficiency calibration of germanium detectors-ND9900 computer systems, Issue 3," Rev. 1
- Chemistry Manual (CM) 5.24B, "Gamma spectrum evaluation, Issue 3," Rev. 0
- CM 5.24C, "Canberra Genie AXP system with CAS software," Rev. 0
- LLD determinations for Unit 2 Canberra Genie AXP counting system (Detector No. 2), October 17, 2001
- Health Physics Program Audit BV-C-01-11 (August 27, 2001 - October 16, 2001)

The inspector also identified and noted the condition and operability of selected installed area and process radiation monitors and any accessible local indication information for those monitors. The inspectors also reviewed for compliance and adequacy the following procedures and calibration records for installed area and process radiation monitors.

- 1 Maintenance Surveillance Procedure (MSP) 43.09-1, "Radiation process monitor RM-RM215B containment gas calibration, Issue 2," Rev. 3 (performed on September 11, 2001)
- 1 MSP-43.08-1, "Radiation process monitor RM-RM215A containment particulate calibration, Issue 2," Rev. 5 (performed on August 24, 2000)
- 1 MSP-43.42-1, "Radiation ion chamber area monitor, RM-RM-201, containment high-range activity calibration, Issue 2," Rev. 5 (performed on June 28, 2001)
- 1 MSP-43.49-1, "RM-RM-208 Drum handling, solid waste building area radiation monitor calibration, Issue 4," Rev. 0 (performed on June 13, 2001)
- 1 MSP-43.53-1, "RM-RM-212, Auxiliary building, sample room, area radiation monitor calibration, Issue 4," Rev. 2 (performed on May 22, 2001)
- 2 MSP-43.16-1, "Reactor coolant letdown high/low range radiation monitor 2 CHS-RQ101A calibration, Issue 4," Rev. 0 (performed on July 11, 2000)
- 2 MSP-43.46-1, 2, "RMR-DAU204, Incore instrumentation area radiation monitor calibration, Issue 4," Rev. 2 (performed on October 03, 2001)
- 2 MSP-43.51-1, 2, "RMP-DAU204, Auxiliary building, elevation 735, area radiation monitor calibration, Issue 4," Rev. 1 (performed on December 21, 2000)
- 2 MSP-43.57-1, 2, "RMP-DAU210, sample room area radiation monitor calibration, Issue 4," Rev. 1 (performed on September 28, 2001)

The inspectors reviewed the adequacy of the program to provide SCBAs for entering and working in areas of unknown radiological conditions and for use in emergency response. The inspection included a review of the status and surveillance records of SCBA air bottles and of SCBAs with air bottles attached, all staged and ready for use in the plant. The following procedures and documents were examined in the course of this review for regulatory compliance and adequacy.

- Health Physics Manual, Appendix 6, “Respiratory protection program,” Rev. 5
- Radiation Protection (RP) 10.24, “Maintenance of Biopak 240P breathing apparatus,” Rev. 4
- ½-Health Physics Procedure (HPP)-3.10.013, “MSA self-contained breathing apparatus,” Rev. 0
- ½-HPP-3.10.022, “Emergency SCBA weekly surveillance,” Rev. 0
- RP 7.3, “Airborne radioactivity sampling,” Rev. 4
- Lesson Plan No. RP-0220, “MSA-401 SCBA operation and use,” Rev. 6
- Lesson Plan No. RP-0225, “Respirator refresher training,” Rev. 10
- Weekly SCBA inspection record for December 3/4, 2001
- SCBA monthly inspection sheets for December 2001

The review was against criteria contained in 10 CFR 20.1501, 10 CFR 20 Subpart H, site TSs, and site procedures.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

.1 Reactor Coolant System Identified Leak Rate

a. Inspection Scope

The inspectors reviewed the Unit 1 and Unit 2 performance indicators (PIs) for identified RCS leak rate for the period January through November 2001. The accuracy of reported data was verified by reviewing selected monthly operating reports, shift operating logs, Licensee Event Reports (LERs), and surveillance tests. Reactor coolant system identified leakage typically remained less than 1 percent (Unit 1) and 2 percent (Unit 2) of the respective TS limits. The inspectors reviewed detailed records for the June and October 2001 periods to determine whether the RCS leak rate data reported was consistent with NRC approved guidance, provided in NEI 99-02.

b. Findings

No findings of significance were identified.

.2 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors reviewed the Unit 1 and Unit 2 PIs for RCS specific activity for the period March through November 2001. The accuracy of reported data was verified by reviewing the results from TS sampling, other chemistry samples of the RCS, and supporting calculations and calculation methodology. RCS activity, for both units, remained less than 1 percent of the respective TS limit. The inspectors verified the RCS specific activity data reported was consistent with NRC approved guidance, provided in NEI 99-02.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Plant Modification Problem Identification and Resolution Assessment

a. Inspection Scope

The inspectors reviewed a sample of CRs documenting problems identified by the licensee in their corrective action program related to plant modifications to verify that the licensee was identifying permanent plant modification issues at an appropriate threshold, entering them in the corrective action program, and corrective actions were appropriate. A listing of the CRs reviewed is provided in Attachment 1. Several minor attention to detail issues with safety evaluations and design change packages (DCP) were identified and described to plant management.

b. Findings

No findings of significance were identified.

.2 Inconsistent Problem Identification & Resolution, and Human Performance

The inspectors identified several problem identification & resolution, and human performance deficiencies as listed below:

- The inspectors identified that corrective actions to a June 22, 2001, Unit 1 LOIA event were not properly implemented as described below:

  -- The extent of condition review for station air compressor preventive maintenance failed to identify manufacturer recommended PMs for the unloader/throttle mechanism. This mechanism subsequently failed twice causing loss of instrument air events on Unit 2 (Section 1R14).
  -- Temporary modification (TM) 1-01-018, written to install an upgraded backup diesel powered station air compressor was deficient prior to the December 7, 2001, Unit 1 loss of instrument air event. The TM did not verify adequate flow-rate capacity to the air receivers to supply system normal air usage requirements and did not include PMT requirements.

These issues were discussed and corrected following the December 7 event and prior to implementation of the TM (Section 4OA3.1).

- On several occasions, station personnel were aware of conditions adverse to quality, but didn't submit CRs until questioned by the inspectors. Examples included unplanned isolation of a Unit 1 pressurizer pressure transmitter (CR 01-7760), unexpected alarm during Unit 2 HHSI flow transmitter calibration (CR 01-7825), and improper scheduling of 'B' intake bay maintenance (CR 01-8420) (Section 1R13).
- Communications deficiencies between operators, technicians, and engineers, which led to unplanned equipment actuation, were discussed in Section 1R12. A similar communication deficiency on November 21, caused Unit 2 operators to fail to recognize that an reactor coolant pump (RCP) under frequency trip channel was inoperable for over 24 hours (CR 01-7684).

4OA3 Event Follow-up

.1 Unit 1 Manual Reactor Trip Due to Loss of Instrument Air Pressure

a. Inspection Scope

On December 7, 2001, at 2:00 p.m., Unit 1 control room operators manually tripped the reactor from 100 percent power in response to a LOIA pressure (CR 01-7966). At 1:53 p.m., with the 'B' station air compressor out of service for planned maintenance, the 'A' station air compressor tripped and instrument air system pressure began to decline. Operators responded in accordance with procedure 1OM-53C.4.1.34.1, "Loss of Station Instrument Air," Rev. 6. Operators started the backup diesel powered air compressor (1SA-C-2), but this compressor's capacity was insufficient to supply the existing instrument air load demand. Instrument air pressure continued to decline, causing the 'C' MSIV to begin closing. Operators promptly tripped the reactor as required by 1OM-53C.4.1.34.1. Prior to the trip, the inspectors responded to the turbine building to evaluate the equipment malfunction and monitor operator attempts to restore instrument air pressure prior to the reactor trip.

Following the trip, the inspectors responded to the control room to evaluate plant equipment and mitigating system response to the trip, operator actions including communications and use of correct EOPs, and plant stabilization to a safe shutdown condition. The inspectors observed operator actions, reviewed various instruments and sequence of events recorders, and conducted interviews to verify safe plant conditions. The inspectors also verified the reactor trip was properly reported in accordance with 10 CFR 50.72. Immediately following plant stabilization the inspectors reviewed the event's risk significance with licensee risk analysts and the NRC regional senior risk analyst. This event was characterized as a reactor trip with the instrument air system, the 'B' river water pump (planned maintenance), and 'B' HHSI pump (planned maintenance) inoperable. The inspectors determined that the conditional core damage probability for this event was very low (approximately 5.3E-6) and that no additional NRC reactive response was necessary.

The inspectors attended the Unit 1 Readiness for Restart Assessment Meeting and monitored various equipment repair activities to determine whether station personnel properly evaluated plant readiness for safe restart in accordance with NPDAP 5.11, “Post-Trip Review,” Rev. 4. The Event Review Team (ERT) determined that the apparent cause of the reactor trip was a failed ‘A’ station air compressor control power fuse, caused by the ongoing work activity on the ‘B’ station air compressor. The inspectors determined that adequate measures were implemented to preclude repetitive challenges to safety-related equipment upon restart, as required by NPDAP 5.11.

b. Findings

The inspectors determined that inadequate work planning and human performance errors caused a Unit 1 LOIA and manual reactor trip. The safety significance of this event was very low (Green) because the performance deficiency did not cause any accident mitigation equipment or functions to be unavailable.

On December 7, 2001, while tightening terminal connections within the ‘B’ station air compressor control cabinet as directed by WO 01-5427, electricians shorted an energized circuit. This overloaded the ‘A’ station air compressor control power fuse, causing the ‘A’ air compressor to trip. The ‘A’ air compressor could not be restarted due to the blown control power fuse. The ERT determined that the equipment clearance, posted to completely deenergize the ‘B’ air compressor prior to beginning work, was inadequate. Work planners failed to identify an energized contact from the ‘1MR’ relay which connected an auto-start feature between the ‘A’ and ‘B’ air compressors. Additionally, electricians used inappropriate tools and failed to adequately perform required safety checks to verify the ‘B’ air compressor circuitry was completely deenergized, as directed in WO 01-5427. The ERT also identified a latent vulnerability of the air system which had not been recognized following a similar reactor trip on June 22, 2001. A modification to the air dryer system several years ago increased air system usage beyond the capacity of the installed backup diesel powered air compressor. As a result, although operators started the diesel air compressor promptly on December 7, they were unable to recover instrument air pressure prior to the reactor trip. An upgraded diesel air compressor was installed following the December 7, 2001, event to correct this latent issue.

The inadequate maintenance issue was more than minor because it had an actual impact on safety. The resulting LOIA caused operators to manually trip the reactor, an initiating event which raised overall plant core damage frequency. The issue was evaluated using the Phase 1 SDP for the initiating event cornerstone. The LOIA increased the likelihood that mitigation equipment (specifically the power conversion system, AFW bleed path, and primary heat removal feed/bleed) would not be available and caused a reactor trip. Therefore, a Phase 2 SDP evaluation was required. Using Tables 1 and 2 of the Beaver Valley Unit 1 Risk Informed Inspection Notebook (Unit 1 specific SDP), the inspectors determined the station instrument air system was effected and the LOIA event scenario applied. The exposure time of the maintenance performance deficiency was less than 3 days. This was the third Unit 1 LOIA event due to performance issues in the past 6 months; therefore, the inspectors raised the estimated likelihood rating for LOIA event one order of magnitude from that shown in Table 1. The inspectors evaluated the four accident sequences listed in Table 3.13 for the LOIA initiating event. Applying the result to the risk significance estimation matrix, shown in Table 4, the inspectors determined the risk associated with this finding was GREEN. Based on this Phase 2 SDP analysis, the inspectors concluded the event had very low safety significance and was a GREEN finding (CR 01-7966). The issue was not a violation of regulatory requirements because instrument air is a nonsafety-related system.

.2 (Closed) LER 05000334/01-01: Manual Reactor Trip Due to Loss of Station Instrument Air.

a. Inspection Scope

This event was previously documented in NRC Inspection Report Nos. 50-334(412)/01-06. The inspectors reviewed the LER and related documentation to verify the event was accurately reported as required by 10 CFR 50.73, causal assessment and corrective actions were appropriate to preclude recurrence, and to determine whether the event was caused by a performance deficiency. This LER was closed during an onsite review.

b. Findings

The inspectors determined that failure to identify and perform PM tasks for instrument air dryer 1IA-D-1 in accordance with manufacturer recommendations was the root cause of the LOIA and subsequent reactor trip. The safety significance of this finding was very low (Green) because the performance deficiency did not cause any accident mitigation equipment or functions to be unavailable.

The ERT determined that the root cause of the event was failure of an internal spring in purge/repressurization valve 1IA-288 on instrument air dryer 1IA-D-1, due to cyclic fatigue. This valve had operated approximately 600,000 cycles since installation in 1995, as compared to the vendor recommended valve service life of 200,000 cycles, without inspection or PM. Based on the manufacturer's information, the spring should have been replaced approximately 4 years prior to it's failure. Failure of the spring caused 1AI-288 to fail open and continuously purge the instrument air supply to atmosphere. Without an intact replenishment supply path, the instrument air header depressurized due to normal instrument air usage. The instrument air depressurization caused a loss of cooling water flow to two RCP motors and thermal barriers. Operators manually tripped the reactor as required by procedure.

The inadequate PM issue was more than minor because it had an actual impact on safety. Operators manually tripped the RCPs and the reactor, as required by procedures. The reactor trip was an initiating event, which raised overall plant core damage frequency. The LOIA increased the likelihood that mitigation equipment (specifically the power conversion system, AFW bleed path, and primary heat removal feed/bleed) would not be available. The LOIA and loss of component cooling water to the RCPs also increased the potential for a RCS leak. The issue was evaluated using the Phase 1 SDP and was determined to effect the initiating event and barrier integrity cornerstones. Therefore, a Phase 2 SDP evaluation was required. Using Tables 1 and 2 of the Beaver Valley Unit 1 Risk Informed Inspection Notebook (Unit 1 specific SDP), the inspectors determined the station instrument air system was effected and the LOIA event scenario applied. The exposure time of the station air system PM performance deficiency was greater than 30 days. Three Unit 1 LOIA events due to performance issues have occurred in the past 6 months; therefore, the inspectors raised the estimated likelihood rating for LOIA event one order of magnitude from that shown in Table 1. The inspectors evaluated the four accident sequences listed in Table 3.13 for the LOIA initiating event. Applying the result to the risk significance estimation matrix, shown in Table 4, the inspectors determined the risk associated with this finding was GREEN. Based on this Phase 2 SDP analysis, the inspectors concluded that the event had very low safety significance and was a GREEN finding (CR 01-3785). The issue was not a violation of regulatory requirements because instrument air is a nonsafety-related system.

4OA5 Other

Administrative Tracking of NRC Unresolved Item for Performance Indicator Verification

In NRC Inspection Report No. 50-334(412)/2001-08, the inspectors questioned whether engineers had properly evaluated an April 21, 2001, Unit 2 power reduction, regarding NRC PI reporting for “Unplanned Power Changes per 7000 Critical Hours.” Engineers initiated CR 01-6679 and frequently asked question (FAQ) IE03 to resolve the concern. NRC Unresolved Item **(URI) 50-412/01-10-02** is established to track this issue pending response to FAQ IE03 by the NEI/NRC performance indicator working group.

4OA6 Management Meetings

.1 Exit Meeting Summary

The inspectors presented the inspection results to Mr. Robert Saunders, Mr. Lew Myers, and other members of licensee management following the conclusion of the inspection on January 11, 2002. The licensee acknowledged the findings presented.

The licensee did not indicate that any of the information presented at the exit meeting was proprietary.

.2 Site Management Visit

On December 10-11, 2001, Mr. Hubert Miller, NRC Region I Administrator; Mr. A. Randolph Blough, Director, Division of Reactor Projects; and Mr. John Rogge, Chief, Projects Branch 7, toured Beaver Valley Power Station and met with station personnel to review plant performance. They met with Mr. Robert Saunders, President FENOC; Mr. Lew Myers, Senior Vice President, FENOC; and other station personnel during the site visit.

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

a. Key Points of Contact

R. Boyle	System Engineer
T. Cosgrove	Manager, Nuclear Regulatory Affairs
R. Donnellon	Director, Beaver Valley Plant Maintenance
C. Hawley	Manager, Design Engineering
D. Huff	Manager, System Engineering
J. Lebda	Supervisor, Radiological Engineering and Health
C. Mancuso	Supervisor, Design Change Implementation
N. Morrison	System Engineer
D. Murry	Nuclear Shift Supervisor
L. Myers	Senior Vice President, FENOC
L. Pearce	Plant General Manager
M. Pearson	Director, Services & Projects
J. Sipp	Manager, Health Physics Manager
B. Sepelak	Supervisor, Nuclear Regulatory Compliance
F. von Ahn	Director, Beaver Valley Nuclear Engineering

b. Items Opened, Closed And Discussed

Opened

50-412/01-10-02	URI	Review of Licensee Report of “Unplanned Power Changes per 7000 Critical Hours” NRC Performance Indicator (Section 4OA5)

Opened/Closed

50-334/01-10-01	NCV	Human Performance, Communication, and Procedural Adherence Deficiencies During Safety Related Maintenance (Section 1R13)

Closed

50-334/01-01	LER	Manual Reactor Trip Due to Loss of Instrument Air (Section 4OA3.2)

c. List of Documents Reviewed

Procedures

1OST-45.11	Cold Weather Protection Verification, Rev. 15
2OST-45.11	Cold Weather Protection Verification, Rev. 14
2OM-45D.3.C	Power Supply and Control Switch List, Rev. 7
SPEAP 3.2	System & Performance Engineering Administrative Procedure, Attachment 13, Maintenance Rule (a)(1) Disposition Review, Rev. 3
SPEAP 3.2	System & Performance Engineering Administrative Procedure, Attachment 14, Maintenance Rule (a)(2) Disposition Review, Rev. 3

10 CFR 50.59 Safety Evaluations

00-006	HHSI full flow test system description, February 8, 2000
00-019	Installation of mechanical clamp on atmospheric steam dump 2SVS-PCV101C, February 21, 2000
00-029	Primary side loose parts, February 24, 2000
00-045	Steam Generator (SG) secondary side foreign objects (1RC-E-1A), March 18, 2000
00-047	SG secondary side foreign objects, (1RC-E-1B,1C), March 22, 2000
00-066	Feedwater isolation valve actuator upgrade (2FWS-HYV157A, B, C), Rev. 1, 10/13/00
00-078	Replacement of BV-2 EDG governor system, August 3, 2000
00-083	Permanent bypass of Gland Seal System exhaust filters, October 4, 2000
00-084	2SWS-1103,1104 repeat failures, September 21, 2000
00-113	Engineered safety features response time, October 23, 2000
01-00019	Loose Parts Monitoring System Modifications, December 06, 2001
01-00025	Control room in-leakage assumed in dose calculations, May 14, 2001
01-01647	Unit 1 ‘B’ RW pump replacement, December 6, 2001

10CFR50.59 Safety Evaluation Screens

01-00147	1RHR pump coupling retrofit modification, August 13, 2001
01-00316	10M-53A.1.FR-P.2, Response to Anticipated Pressurized Thermal Shock Condition, June 15,2001
01-00325	10M-53B.1.ECA-3.1, SGTR With Loss of Reactor Coolant - Subcooled Recovery Desired, June 15, 2001
01-00331	1OM-53B.1.ES-3.1, Post SGTR Cooldown Using Backfill Background, June 15, 2001
01-00374	2OM-52A.1.FR-P.1, Response to Anticipated Pressurized Thermal Shock Condition, June 15, 2001
01-00375	2OM-52A.1.FR-P.2, Response to Anticipated Pressurized Thermal Shock Condition, June 15,2001
01-00716	Borg-Warner pressure switch replacement, August 7, 2001
01-01543	RV-1SI-894 setpoint change and valve replacement, August 21, 2001
01-01558	Containment isolation check valve test procedure, August 22, 2001
01-02188	BV1 Small Bore Deficiencies 9/30/01

01-02616	Diesel air compressor 1SA-C-2 temporary replacement, November 1, 2001
DCP-2235	Upgrade Unit 1 emergency diesel generator fuel oil filters, August 16, 1999
DCP-2287	Upgrade Unit 2 standby service water pumps seal water piping, February 28, 2000
DCP-2385	2SWS-1103, 1104 repeat failures, August 12, 2000
DCP-2386	Replacements of Unit 1 RCP seal leak-off flow transmitters, May 18, 2001
DCP-2410	BV1 small bore deficiencies, Rev. 1, May 31, 2001
DCP-2416	Replacement of Unit 1 RWST level transmitters, June 1, 2001
DCP-2419	Replacement of SWS 6" headers to control room chillers, April 26, 2001

Plant Modification DCPs

1957	Permanent bypass of GSS exhaust filters, August 10, 2000
2171	Feedwater isolation valve nitrogen system upgrade (2FWS-HYV157A, B, C), June 30, 2000
2236	Replacement of U2 emergency diesel generator governor system, August 3, 2000
2382	Loose Parts Monitoring System Modification Unit 1, December 6, 2001
2385	2SWS-1103, 1104 repeat failures, August 12, 2000
2402	Borg-Warner pressure switch replacement, September 6, 2001
2410	BV1 Small Bore Design Deficiency, Design Change Summary 3/05/01
2416	Replacement of RWST level transmitter, July 20, 2001
2424	Unit 1 river water pump replacement, November 30, 2001

Condition Reports

01-6896
01-7509
97-0515
97-2142
99-2038
99-2129
00-0128
00-0130
00-3139
00-3147
00-3524
00-3991
00-4126
00-4465
01-0647
01-0964
01-1550
01-2773
01-3384
01-7190
01-7314
01-7316
01-7397
01-7406
00-028179-002
00-029633-000
00-030461-000
00-030804-000
00-030804-001
01-004268-000
01-004268-001
01-014325-000
01-014326-000
01-017445-000
01-022409-000
01-022516-000
00-0912
00-1381
00-2802
00-2950
00-3534
00-3742
01-1209
01-1337
01-1343
01-4990
01-5015
01-5160
01-5379
01-6216
01-6297
01-6422
01-6500
01-6596
01-6602
01-6605
01-6618
01-7135

01-7306	01-8040
01-7988	01-8064
01-8001	01-8074
01-8016	01-8082

Work Orders

00-007520-000
00-016301-002
00-016447-000
00-021534-000
00-021534-001

Other Documents

1-18-038	Loose Part Monitoring Beaver Valley Power Station (BVPS) 1 Change Notice, April 23, 2001
10M-53A.1.FR-P.1	Response to Imminent Pressurized Thermal Shock Condition, June 28, 2001
10M-53A.1.FR-P.2	Response to Imminent Pressurized Thermal Shock Condition, June 28, 2001
12241-FWS-10-1-C	Setpoint Calculation for 2 FWS-PS 157A1/B1/C1 and 2 FWS-PS 157A2/B2/C2, Pressure Switches for Operator of Feedwater Isolation Trip Valves, Rev. 1
2CMP-24FWS-HYV157 - A, B, C	Unit 2 Maintenance Procedure, “Feedwater Isolation Trip Valve Accumulator Fill”, Rev. 0
2OM-24.4.AAG	Unit 2 Alarm Response Procedure, “Feedwater Isolation Valves Nitrogen Pressure Low”, Rev. 6&7
8700-DMS-0477	Specification for Unit 1 River Water Pumps, Rev. 1
BCO 1-97-007	Small Bore Safety-Related Piping Operability BVPS Unit 1, June 10, 1999
BV-C-01-10	Engineering Design and Control Audit, July 12 through August 31, 2001
C.M.1.11	Secondary Water Chemistry Monitoring Program, Rev. 2
Drawing 33463-1	Unit 1 River Water Pump Performance Curve - Old (Byron-Jackson), Rev. 0
Drawing TC-10135	Unit 1 River Water Pump Performance Curve - New (Johnston Pump), Rev. 0
Drawing 71598-D	Unit 1 River Water Pump - Sectional Drawing (Johnston Pump), Rev. 1
Drawing 8700-RC-32E	Unit 1 Intake Structure - Miscellaneous Details, Rev. 12
EM 200105	BVPS Engineering Memo, Flushing Flux Thimble Guide Path Features, January 18, 2000
EM 113171	Licensing Evaluation of Removal of Loose Parts Monitoring System BVPS 1, June 25, 1997
EM-109232	SECL-95-004 Beaver Valley Unit 1 Safety Evaluation for Loose Parts, March 21, 1995
L-99-082	Safety-Related Small Bore Piping Evaluation Project Unit 1, Rev. 1

UFSAR 4.2.10	Loose Parts Monitoring BVPS 1

d. Acronyms Used

ADAMS	NRC's Document System
AFW	Auxiliary Feedwater
ASME	American Society of Mechanical Engineers
BVPS	Beaver Valley Power Station
BVT	Beaver Valley Test
CFR	Code of Federal Regulations
CM	Chemistry Manual
CR	Condition Report
DCP	Design Change Package
DEP	Drill/Exercise Performance
EOP	Emergency Operating Procedure
EP	Emergency Preparedness
EPIP	Emergency Plan Implementing Procedure
ERT	Event Review Team
FAQ	Frequently Asked Question
FENOC	FirstEnergy Nuclear Operating Company
gpm	Gallon per Minute
HHSI	High Head Safety Injection
HPP	Health Physics Procedure
I&C	Instrumentation and Control
JPM	Job Performance Measures
LER	Licensee Event Report
LOIA	Loss of Instrument Air
MR	Maintenance Rule
MSIV	Main Steam Isolation Valve
MSP	Maintenance Surveillance Procedure
NCV	Non-Cited Violation
NDE	Non-Destructive Evaluation
NEI	Nuclear Energy Institute
NPDAP	Nuclear Power Division Administrative Procedure
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NUREG	NRC Technical Report Designation
OM	Operating Manual
OMDG	Operations Management Desktop Guide
OST	Operating Surveillance Test
PARS	Publicly Available Records
PI	Performance Indicator
PM	Preventive Maintenance
PMT	Post-Maintenance Test
PT	Pressure Transmitter
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RIP	Radiological Instrumentation Procedure
RP	Radiation Protection

RPI	Rod Position Indicator
RW	River Water
RWST	Refueling Water Storage Tank
SCBA	Self-Contained Breathing Apparatus
SDP	Significance Determination Process
SG	Steam Generator
SPEAP	System Performance Engineering Administrative Procedure
SRM	Smart Radiation Monitor
SSC	Structures, Systems, and Components
SW	Service Water
SWS	Service Water System
TCN	Temporary Change Notice
TM	Temporary Modification
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WO	Work Order