September 14, 2000

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

SUBJECT: NRC'S BEAVER VALLEY INSPECTION REPORT 05000334/2000-006; 05000412/20000-006)

Dear Mr. Myers:

On August 12, 2000, the NRC completed an inspection at the Beaver Valley 1 & 2 reactor facilities. The enclosed report presents the results of that inspection. The results of this inspection were discussed on August 23, 2000, with you and members of your staff.

This inspection was an examination of 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. Within these areas, the inspection consisted of a selected examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection, the NRC identified two findings that were evaluated under the significance determination process and were determined to be of very low safety significance (Green). One of the findings involved failure to incorporate supplemental leak collection and release system design requirements into emergency operating procedures and was a violation of NRC requirements. This violation is being treated as a non-cited violation (NCV), consistent with Section VI.A of the Enforcement Policy issued on May 1, 2000 (65 FR 25368). If you contest the violation or severity level of the NCV, 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, and the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001, and the NRC Resident Inspector at the Beaver Valley facility.

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We appreciate your cooperation. Please contact me at 610-337-5146 if you have any questions regarding this letter.

Sincerely,

/RA/

John F. Rogge, Chief
Projects Branch 7
Division of Reactor Projects

Docket Nos.: 05000334; 05000412
License Nos: DPR-66, NPF-73

Enclosure: Inspection Report 05000334/2000-006; 05000412/2000-006

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REGION I

Docket Nos.	05000334, 05000412
License Nos.	DPR-66, NPF-73
Report Nos.	05000334/2000-006, 05000412/2000-006
Licensee:	FirstEnergy Nuclear Operating Company
Facility:	Beaver Valley Power Station, Units 1 and 2
Location:	Post Office Box 4 Shippingport, PA 15077
Dates:	July 2, 2000 through August 12, 2000
Inspectors:	D. Kern, Senior Resident Inspector G. Dentel, Resident Inspector G. Wertz, Resident Inspector J. Jang, Senior Health Physicist M. Gray, Reactor Engineer
Approved by:	J. Rogge, Chief Projects Branch 7 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000334-00-06, IR 05000412-00-06, on 07/02-08/12/2000; FirstEnergy Nuclear Operating Company; Beaver Valley Power Station; Units 1 & 2. Maintenance Risk Assessment and Emergent Work Control, Event Follow-up, and Problem Identification and Resolution.

The inspection was conducted by resident inspectors, two regional engineering specialists, and a regional health physics inspector. The inspection identified two green issues, one of which was a non-cited violation, and a cross-cutting issue which was assigned no color. The safety significance of issues is indicated by their color (green, white, yellow, red) and was determined by the Significance Determination Process (SDP) in Inspection Manual Chapter 0609 (see Attachment 1).

Cornerstones: Mitigating Systems/Barrier Integrity

- **Green** Safety related equipment was taken out of service for maintenance that did not need to be performed, which unnecessarily increased safety system unavailability. Preventive maintenance was incorrectly scheduled for an emergency diesel generator (EDG) 2 years ahead of its periodic due date. Poor work coordination further extended the duration of the outage. On two occasions poor communications between operating crews resulted in safety related heat exchangers being unnecessarily disassembled to investigate increased differential pressure. No fouling was found. In both cases, the change in differential pressure was the direct result of configuration changes made by the operating crews.

  The finding was determined to have very low safety significance, because redundant mitigating equipment was available during the periods these components were out of service for maintenance. No violations of NRC requirements were identified. (Section 1R13.1)

- **Green** Original design requirements of the supplemental leak collection and release system (primary auxiliary building ventilation) were not incorporated into plant procedures. Specifically, the system is a manual system and emergency operating procedures did not have requirements to verify the ventilation fan was operating. The system provides two safety functions: 1) filter leakage from engineered safety feature equipment, and 2) provide cooling to safety related motors.

  The finding was determined to have very low safety significance. Engineers determined the loss of cooling to safety related motors would not affect the ability of these motors to function during the initial accident mitigation stages and operators would have sufficient time to correct the problem prior to equipment failure. Failure to incorporate design requirements into procedures was a non-cited violation of 10 CFR 50 Appendix B Criterion III, consistent with Section VI.A of the Enforcement Policy, issued on May 1, 2000. (Section 4OA3.2)

Cross-cutting Issues: Problem Identification and Resolution

- **No Color** On several occasions station personnel either did not initiate condition reports for conditions adverse to quality, incorrectly or incompletely evaluated the causes, or assigned incorrect priorities to resolve problems. Condition reports were not written for electro hydraulic control system post-maintenance testing deficiencies and unnecessary emergency diesel generator unavailability until after being identified by the inspectors. Evaluation of nuclear instrument N42 miscalibration did not address double verification errors or questioning of unexpected equipment response. Evaluation of nuclear instrument N44 miscalibration mischaracterized the cause as drift and assigned no further action when further investigation was warranted. Additionally, a recent Independent Safety Evaluation Group assessment of NRC Performance Indicator Process implementation did not identify several readily apparent process or reporting errors, which were later identified by the NRC inspectors. (Section 4OA4)

Report Details

SUMMARY OF PLANT STATUS: Unit 1 began this inspection period at 100 percent power. On July 5, 2000, the main turbine electro hydraulic control circuit failed and led to an automatic reactor trip. Operators resynchronized the unit to the grid on July 7 and achieved full power on July 9. On July 14, a `B' main feedwater pump seal leak required prompt reduction to 62 percent power to perform repairs. The unit returned to full power on July 15 and, with the exception of load following activities, remained at full power for the remainder of the inspection period. Unit 2 operated at or near full power for the entire inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignments

a. Inspection Scope

- The inspectors performed a partial system walkdown of the Unit 1 Quench Spray system. The inspectors reviewed the system alignment as described on plant drawing Operating Manual (OM) Figure No. 13-1, "Valve Operation Number Drawing, Containment Depressurization System," Rev. 11, and performed field verification of major equipment alignment. The inspectors identified a temporary wooden structure located by the refueling water storage tank. This structure was subsequently evaluated and removed after investigation was completed under condition report (CR) 00-2564.

- The inspectors performed a partial system walkdown of the Unit 2 High Head Safety Injection (HHSI) system. The inspectors reviewed the system alignment as described on plant drawings 10080-RM-407-1A and 10080-RM-407-2 and performed a field verification of major equipment alignment.

- The inspectors performed a partial system walkdown of the Unit 2 Emergency Diesel Generator (EDG) system. The inspectors reviewed the system alignment as described on plant drawings 10080-RM-436-1 through 6 and in plant procedures 2OM-36.3.C.8 (9), Power Supply and Control Switch List - Diesel Generator 2-1(2), Rev. 9 (10).

b. Issues and Findings

There were no findings identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors reviewed the fire protection analyses for both units and inspected the following risk significant areas:

- Unit 1 communication equipment and relay panel room

- Unit 1 process instrument room
- Unit 2 cable vault and rod control area

Specific fire protection conditions examined included control of transient combustibles, material condition of fire protection equipment, and the adequacy of any fire impairments and compensatory measures.

b. Issues and Findings

There were no findings identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed Unit 1 operator requalification testing focusing on human performance of time critical tasks. The inspectors reviewed the operators' ability to correctly evaluate the training scenario and implement the emergency plan. The inspectors reviewed time critical tasks, operator actions, and the corresponding assumptions in the licensee's probabilistic risk assessment. The inspectors also evaluated whether deficiencies were identified and discussed during critiques.

b. Issues and Findings

There were no findings identified.

1R12 Maintenance Rule Implementation

.1 Biennial Maintenance Rule Implementation Assessment

a. Inspection Scope

The inspectors reviewed the periodic evaluations required by 10 CFR50.65 (a)(3) for Beaver Valley Power Station, Units 1 and 2 to verify that structures, systems and components (SSCs) within the scope of the maintenance rule were included in the evaluations and balancing of reliability and unavailability was given adequate consideration. The inspectors reviewed the licensee's most recent periodic evaluations which covered the period from November 1, 1998 through May 31, 2000.

The inspectors selected the following safety significant systems in a(1) status to verify that; (1) goals and performance criteria were appropriate, (2) industry operating experience was considered, (3) corrective action plans were effective, and (4) performance was being effectively monitored.

- Beaver Valley Unit 1 120 VAC Distribution System
- Beaver Valley Unit 2 Reactor Coolant System
- Beaver Valley Unit 2 Main Feedwater System
- Beaver Valley Unit 2 Primary Component and Neutron Shield Tank Cooling Water System

- Beaver Valley Unit 2 Compressed Air System
- Beaver Valley Unit 2 Emergency Diesel Generator System
- Beaver Valley Unit 2 125 VDC Distribution System
- Beaver Valley Unit 2 Atwood & Morrill Check Valves

The inspectors reviewed the following safety significant systems in a(2) status to verify that system performance compared to the licensee’s performance criteria was acceptable.

- Beaver Valley Unit 1 Chemical & Volume Control System
- Beaver Valley Unit 2 Chemical & Volume Control System
- Beaver Valley Unit 1 Residual Heat Removal System
- Beaver Valley Unit 2 Residual Heat Removal System
- Beaver Valley Unit 1 Containment Depressurization System
- Beaver Valley Unit 2 Containment Depressurization System
- Beaver valley Unit 1 Auxiliary Feedwater System
- Beaver valley Unit 2 Auxiliary Feedwater System

Documents used for this inspection included the following:

- NPDAP 8.30, “Maintenance Rule Program,” Rev. 5
- SPEAP 2.2, “System Monitoring and Trending,” Rev. 2
- SPEAP 2.11, “Risk Based System Engineering Priority,” Rev. 0
- SPEAP 3.2, “Maintenance Rule Program Administration,” Rev. 4
- FENOC Maintenance Rule Monthly Monitoring Reports for April, May and June 2000
- Completed SPEAP 3.2, Attachment 15 Forms, “SPED Engineer Input to Periodic Maintenance Rule Assessment, for assessment period November 1, 1998 to May 31, 2000"
- List of Beaver Valley Unit 1 and 2 systems within Maintenance Rule scope
- Beaver Valley Maintenance Rule System Basis Documents for Each System Reviewed
- System Health Reports for the second quarter, 2000.

b. Issues and Findings

There were no findings identified.

.2 Unit 1 Electro Hydraulic Control System Failure Assessment

a. Inspection Scope

The inspectors evaluated Maintenance Rule (MR) implementation for the issue listed below. Specific attributes reviewed included MR scoping, characterization of failed SSCs, MR risk categorization of SSCs, SSC performance criteria or goals and appropriateness of corrective actions.

- On July 5, 2000, a Unit 1 main turbine electro hydraulic control (EHC) system failure caused four turbine throttle valves to shut which led to an automatic reactor trip. Engineers determined that the root cause was a failed solid state mixing amplifier card. This failure was unrelated to a November 1999 EHC power supply failure for which the turbine had been taken off-line to perform repairs. Engineers determined that the failure was not a maintenance preventable functional failure and turbine system remained a category (a)(2) system following the trip.

b. Issues and Findings

There were no findings identified.

1R13 Maintenance Risk Assessment and Emergent Work Control

.1 Unnecessary Out of Service Time for Unit 1 Emergency Diesel Generator

a. Inspection Scope

As a result of past valve leakage problems, the inspectors reviewed planned preventive maintenance (PM) work order (WO) 00-007450-000 to clean and inspect the EDG 1-1 heat exchanger `A' river water outlet vacuum break check valve. This work activity necessitated EDG 1-1 being removed from service for 5.5 hours. The inspectors reviewed scheduling and control of the work activity in order to evaluate the effect on plant risk.

a. Issues and Findings

The inspectors identified, that on several occasions, safety related equipment was taken out of service for maintenance that did not need to be performed. The unnecessary maintenance increased safety system unavailability.

The EDG work activity was evaluated with the station's probabilistic risk assessment process and performed in accordance with the schedule. However, the inspectors noticed a delay in the duration of the maintenance of almost 2 hours due to poor work coordination. Specifically, an unrelated departmental briefing delayed the mechanic from verifying the clearance and obtaining the proper tools. Due to the increase in out of service time for a risk significant component, the inspectors discussed this delay with the mechanical lead coordinator who initiated condition report (CR) 00-2562.

The inspectors also identified that the check valve had recently been replaced (January 2000). Based on the PM frequency of 144 weeks, this PM was not due for over 2 more years. The inspectors questioned the river water system engineer who agreed that the PM should have been rescheduled due to the valve replacement. The inspectors determined that the PM performance was premature and that it resulted in unnecessary planned unavailability hours for EDG 1-1. Approximately 2 weeks after this event, no CR had been initiated to address the PM scheduling problem (see Section 4OA4).

The unnecessary EDG maintenance and resulting period of inoperability was evaluated using the SDP phase 1 and determined to affect the "Mitigating Systems" cornerstone. The finding represented an actual loss of safety function of a single emergency power train for less than the technical specification (TS) allowed outage time, and therefore resulted in a GREEN finding.

The inspectors recently observed two additional examples of unnecessary maintenance on safety related equipment (Unit 2 component cooling water (CR 00-2129) and Unit 2 control room air conditioning (CR 00-2474). In both cases operators noted high heat exchanger differential pressure and requested maintenance personnel to disassemble and inspect the heat exchangers for potential fouling. The heat exchangers were inspected and no fouling was noted. The increased differential pressure was later determined to be the direct result of equipment configuration changes which operators had made on earlier shifts. The configuration changes were not logged or otherwise communicated between operating crews.

.2 Other Planned and Emergent Work Activities

a. Inspection Scope

The inspectors reviewed scheduling and control of maintenance activities in order to evaluate the effect on plant risk. The inspectors reviewed routine planned maintenance and emergent work for the following equipment removed from service:

- Emergent work was performed on the Unit 1 control rod drive motor generator #1 Set (1ROD-MG-1). The inspectors evaluated control over the troubleshooting, subsequent repairs, and return to service after the motor generator set showed degradation and was secured on July 11. The return to service was completed using WO 00-013038-001 and 1OM-1.4.B, “Full-Length Rod Control System Startup,” Rev. 13.

- Emergent work was performed on the Unit 1 overpressure delta temperature (OPDT) comparator. An instrumentation and control supervisor demonstrated a questioning attitude in identifying a relay chattering that was associated with OPDT reactor protection channels. This quick identification allowed corrective actions prior to an actual failure. The inspectors observed troubleshooting and repairs to the OPDT channels conducted using WO 00-016452-000/001. (CR 00-2512)

- Emergent work was performed on the Unit 1 overtemperature delta temperature (OTDT) and OPDT reactor protection channels. The inspectors reviewed corrective actions to specific inputs to the OTDT and OPDT being found outside the allowable tolerance band (allowable values). This was the third out of four surveillances conducted since the Unit 1 refueling outage where the channels were found outside the allowable tolerance band. The maintenance was performed using 1MSP-6.20-I, “Delta T TAVG Protection Instrument Channel 1 Test (T-RC412),” Rev. 11 and 1MSP-6.38-I, “T-RC412 Delta T TAVG Protection Instrument Channel 1 Calibration,” Rev. 8, (CR 00-2623, CR 00-1797, and CR 00-1734). The surveillance interval was subsequently shortened in response to the channels repeatedly being found out of the allowable tolerance band.

b. Issues and Findings

There were no findings identified.

1R14 Personnel Performance During Non-routine Plant Evolutions

a. Inspection Scope

The inspectors reviewed operator performance during the following nonroutine plant evolution:

- Unit 2 Control room operators response to unplanned actuations of single OPDT and OTDT reactor protection system (RPS) channels on July 6. The RPS channel actuations were a result of misuse of a digital voltmeter by a maintenance technician. The operators immediately recognized the cause of the RPS actuation to be a work activity which had been discussed during shift turnover, contacted the technicians, and instructed them to remove the voltmeter connections. The RPS channels immediately returned to normal status. Condition report 00-02285 was initiated. (See Section 1R22 for additional details on the surveillance test.)

b. Issues and Findings

There were no findings identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed operability evaluations in order to determine that proper operability justifications were performed for the following items:

- Unit 1 reactor coolant system loop 2 delta temperature data was identified as outside the allowable band during 1MSP-6.79.I, “Operational Alignment of Process Temperature Instrumentation,” Rev. 6. The channel associated with loop 2 was declared inoperable and immediate actions were taken. The cause of the problem was failure to rescale the delta temperature values after the last surveillance. This resulted from poor technician knowledge of the expected response of delta temperature to changes in the reactor (CR 00-2465).

- Unit 2 `C’ HHSI pump was declared inoperable on July 8 due to excessive casing drain valve (2CHS-295) leakage which occurred when the pump was placed into service. This leakage exceeded the 10 gallons per minute (gpm) limit of TS 3.4.6.2, for identified reactor coolant system (RCS) leakage. The leaking valve was tightened, the leakage reduced below the TS limit, and the pump was declared operable. A temporary modification was subsequently installed to resolve the leakage concern (see Section 1R23). The inspectors reviewed the associated operability assessment.

- Unit 2 `B' HHSI pump experienced low service water (SW) flow to its lubricating oil cooler on July 17. The inspectors recognized the similarity of this condition to a previous event documented in NRC Inspection Report 05000334/2000-004; 05000412/2000-004. However, in this case, the `B' HHSI pump had already been declared inoperable while it was being placed into service and the `C' HHSI pump was being removed from service. The cause of the low flow condition was due to both HHSI pump lubricating oil coolers receiving SW flow concurrently during this realignment. This condition was documented in CR 00-2376. Operability of the HHSI pump was restored after completion of the pump realignment.

- Unit 2 `B' HHSI pump developed an oil leak on July 12 of approximately five drops per minute. The Nuclear Shift Supervisor (NSS) and system engineer assessed the leakage and determined that the pump remained operable. The inspectors discussed the extent of the leak with the system engineer and concluded that the HHSI pump could perform its required safety function.

b. Issues and Findings

There were no findings identified.

1R16 Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed the cumulative effect of the operator workarounds on the reliability, availability, and potential for misoperation of safety systems for Unit 2. The inspectors' review also included a focus on workarounds that could increase an initiating event frequency or affect multiple mitigating systems. In addition, the cumulative effect of workarounds on the ability of the operators to respond in a timely and correct manner to plant transients was also included in the review.

b. Issues and Findings

There were no findings identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed and/or observed several post-maintenance tests (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.

- Technicians replaced the Unit 1 main turbine EHC mixing amplifier #3 card, replaced the +15 volt primary power supply, and reset the various EHC power supply output setpoints following the July 5, 2000, reactor trip (see Section 4OA3.1). Post-maintenance testing included calibration data measurements recorded during troubleshooting and following component replacements and WO 00-012857-001 which verified proper power supply operation with the turbine operating at synchronous speed.

- Diesel Generator Heat Exchanger 1A River Water outlet vacuum break check valve PMT following a preventive maintenance inspection.

- 2OM-30.4.M, “BV-2 Asiatic Clam and Zebra Mussel Chemical Treatment Program,” Rev. 14 following chemical cleaning of the Unit 2 SW system. Specific flow monitoring data used to identify potential macrobiological fouling was reviewed.

b. Issues and Findings

There were no findings identified (see Section 4OA4 for related issue).

1R22 Surveillance Testing

.1 Unit 2, Power Range Nuclear Instrument Calibration

a. Inspection Scope

While performing control room walkdowns, the inspectors were informed that the Unit 2 N42 power range nuclear instrument (PRNI) had been miscalibrated and as a result the loop `B’ OTDT runback and reactor trip channels were inoperable. Operators applied TS 3.3.1.1 limiting conditions of operation until technicians recalibrated the N42 channel. The licensee determined that technicians had incorrectly transferred calibration data and as a result had miscalibrated the instrument. Engineers determined that the miscalibration was in the conservative direction and did not adversely affect safety (Category 2 CR 00-2216). Two days later, operators observed unexpected delta flux alarms and N44 delta flux indication fluctuations immediately following calibration of the N44 instrument. Technicians readjusted the N44 calibration settings and informed the Nuclear Shift Supervisor that the alarms had been due to instrument drift (Category 3C CR 00-2244). The delta flux indication and alarms responded properly for the month following the readjustment. The inspectors conducted interviews, reviewed operating logs, and reviewed various test documents listed below to verify as-left instrument operability and determine whether the surveillance testing problems were properly identified, evaluated, and resolved through the corrective action program.

2RST-2.3,	"Nuclear Power Range Calibration," Rev. 4
2RST-2.6,	"Incore/Excore Axial Imbalance Check," Rev. 3
2RST-2.9,	"Nuclear Instrumentation System Single Point Calibration," Rev. 1
2MSP-2.04.I,	"PRNI Flux Channel N42 Refueling Calibration," Rev. 9
2MSP-2.06.I,	"PRNI Flux Channel N44 Refueling Calibration," Rev. 7

b. Issues and Findings

There were no findings identified (see Section 4OA4 for related issue).

.2 Routine Surveillance Testing

a. Inspection Scope

The inspectors observed and reviewed the following operational surveillance tests (OSTs) and maintenance surveillance procedures (MSPs), concentrating on verification of the adequacy of the test to demonstrate the operability of the required system or component safety function.

- The Unit 1 startup after the July 5 reactor trip and the corresponding procedures including 1OM-52.4.A, "Increasing Power from 5 percent Reactor Power and Turbine on Turning Gear to Full Load Operation," Rev. 35 and 1OST-26.4, "Pedestal Checks," Rev. 6.

- 2MSP-6.79-I, Operational Alignment of Process Instrumentation, Rev. 3. The inspectors reviewed this MSP as a result of an inadvertent RPS channel actuation on July 6 (see Section 1R14). The RPS channel actuation was due to a lack of worker knowledge on the use of a low impedance digital voltmeter. The workers questioned the voltmeter jack input configuration but did not recognize the potential effect for a low impedance circuit on the RPS system. The licensee entered the event into their corrective action program as CR 00-02285.

- 2MSP-39.03-E, "Battery No. 2-2 Test and Inspection," Rev. 8. The inspectors reviewed this MSP as a result of recent degraded battery performance (see NRC Integrated Inspection Reports 05000334(412)/2000-005) and recent surveillance test data which indicated that several individual cells had lower than expected voltage and/or specific gravity after completion of an equalizing charge. Although low, the cells remained above the TS required limit for voltage and specific gravity.

b. Issues and Findings

There were no findings identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed temporary modifications (TMs) and associated implementing documents to verify the plant's design basis and effected system or component operability were maintained. Nuclear Power Division Administrative Procedure, "Temporary Modifications," Rev. 8, specified requirements for development and installation of TMs. The inspectors reviewed temporary modifications associated with the following items:

- Unit 1 TMs for their cumulative impact on safety. In addition, the inspectors examined temporary modification, TM 1-00-009, "Leads lifted on PS-VS-106A/B to prevent trip of SLCRS Fans" for the effect on the operability on the supplementary leak collection and release system (SLCRS). The modification was installed to reduce the likelihood of an inadvertent SLCRS shutdown. The inspectors used NRC Generic Letter No. 91-18, "Information to licensees regarding NRC inspection manual section on resolution of degraded and nonconforming conditions," Rev. 1 to evaluate operability.

- Unit 2 'C' HHSI Pump Casing Drain Valve 2CHS-295 leakage exceeded the TS RCS identified leakage limit of 10 gpm. The valve was tightened and the leakage was reduced to below the TS 10 gpm limit. Temporary modification 2-00-08, "2CHS-295 Blank Flange to Eliminate Excessive Leakage," was installed between the pump and the casing drain valve. The inspectors reviewed the modification package including the design analysis and performed a field walkdown of the installation.

- Five TMs were developed as contingency actions to improve the organizations' readiness to quickly restore operability in the event the 2-2 125 volt station battery continued to degrade (documented in NRC Integrated Inspection Reports 05000334(412)/2000-005). Temporary modification 2-00-006, "Secure a Temporary Replacement Battery Jar to the 2-2 Station Battery Rack, Staged and Ready to be Electrically Connected Incase of a Degraded Cell Event," was implemented. The remaining four TMs associated with physically jumpering an inoperable cell and maintaining an operable 59 cell station battery, and/or connecting the staged replacement battery jar were approved and maintained in the control room as contingencies. The inspectors also walked down TM 2-00-006 to verify it was installed as specified.

b. Issues and Findings

There were no findings identified.

2. RADIATION SAFETY

Cornerstone: Pubic Radiation Safety

2PS1 Radiological Environmental Monitoring Program (REMP)

a. Inspection Scope

The inspector reviewed the following documents or performed the following activities to ensure that the licensee met the requirements specified in the Technical Specification/Offsite Dose Calculation Manual (TS/ODCM):

(1) the 1999 Annual REMP Report;
(2) the most recent ODCM (Revision 14, March 30, 2000) and technical justifications for ODCM changes, including sampling locations;
(3) the most recent calibration results of the primary and backup meteorological monitoring instruments for wind direction, wind speed, and temperature at 33-ft, 150-ft, and 250-ft levels;
(4) operability of the meteorological monitoring instruments;
(5) the most recent calibration results for air samplers;
(6) the licensee's Quality Control evaluation of the interlaboratory comparison program and the corrective actions for any deficiencies;
(7) condition reports: (1) 00-0681; (2) 99-2653; and (3) 99-3108
(8) self-assessments;
(9) the 1999 Quality Assurance audit (BV-C-99-12) for the REMP/ODCM implementations;
(10) the Land Use Census procedure and the 1999 results;
(11) walk-down for determining whether air samplers, milk farms, composite water sampler, vegetable garden, and thermoluminescent dosimeters were located as described in the ODCM and for determining the equipment material condition;
(12) observation of milk and water sampling techniques; and
(13) associated REMP procedures, including vendor's analytical procedures.

b. Issues and Findings

There were no findings identified.

2PS2 Radioactive Material Control Program

a. Inspection Scope

The inspector reviewed the following documents to ensure that the licensee met the requirements, specified in the licensee's program for the unrestricted release of material from the Radiologically Controlled Area (RCA):

a. the methods used for control, survey, and release from the RCA;
b. the most recent calibration results for the radiation monitoring instrumentation, including the (a) alarm setting, (b) respond to the alarm, and (c) the sensitivity;
c. the licensee's criteria for the survey and release of potentially contaminated material; and
d. associated procedures and records to verify for the lower limits of detection.

b. Issues and Findings

There were no findings identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

1. High Head Safety Injection and Auxiliary Feedwater Safety System Unavailability

a. Inspection Scope

The inspectors reviewed the Unit 1 and 2 performance indicators for the HHSI and auxiliary feedwater (AFW) systems. The inspectors verified accuracy of the reported data through reviews of the last six months of reported data, shift technical advisors ' logs, and the June 2000 shift operator logs. In addition, the following procedures were reviewed to evaluate determination of availability.

- 1OST-24.1 "SG Aux Feed Pumps Discharge Valves Exercise," Rev. 9
- 1OST-24.2 "Motor Driven Auxiliary Feed Pump Test [1FW-P-3A]," Rev. 16
- 1OST-24.3 "Motor Driven Auxiliary Feed Pump Test [1FW-P-3B]," Rev. 15
- 1OST-24.4 "Steam Turbine Driven Auxiliary Feed Pump Test [1FW-P-2]," Rev. 15
- 2OST-30.01B "Standby Service Water Pump [2SWE-P21B] Test," Rev. 13
- 2OST-30.6 "Service Water Pump [2SWS-P21C] Test," Rev. 19
- 2OST-7.5 "Centrifugal Charging Pump [2CHS-P21B]," Rev. 17
- 2OST-1.11B "Safeguards Protection System Train 'A' SIS Go Test," Rev. 20

b. Issues and Findings

The inspectors identified instances where operator action was incorrectly credited to maintain equipment available in the Unit 1 auxiliary feedwater system. For example, during the Unit 1 surveillance on the steam driven auxiliary feedwater system, the trip throttle valve was placed in the tripped position. The AFW train was not considered unavailable during the evolution. Based on the guidance in Nuclear Energy Institute (NEI) 99-02 "Regulatory Assessment Performance Indicator Guideline," Rev. 0 and OM Chapter 48.1.I "Conduct of Operations; Technical Specification Compliance," Rev. 8, this equipment should have been declared unavailable because the actions required for system restoration (relatching the trip throttle valve) are more than an uncomplicated operator action with virtual certainty of success. The Unit 1 operations manager acknowledged the findings and CR 00-2712 was initiated to reevaluate various safety system unavailability identification practices. The inspectors determined that the number of additional unavailability hours would not change the significance (color) of the reported values for the performance indicator. The licensee planned to include the additional unavailability hours in the next quarterly update of the performance indicators.

.2 Radiological Effluent Technical Specification/ODCM Radiological Effluent Occurrences

a. Inspection Scope

The inspector reviewed the following documents to ensure the licensee met all requirements of the performance indicator from the third quarter 1999 to the second quarter 2000:

- Monthly projected dose assessment results due to radioactive liquid and gaseous effluent releases; and
- Quarterly projected dose assessment results due to radioactive liquid and gaseous effluent releases.

b. Issues and Findings

There were no findings identified.

.3 Performance Indicator Data Collecting and Reporting Process Review (TI2515/144)

a. Inspection Scope

The inspectors reviewed the Beaver Valley performance indicator (PI) data collecting and reporting process to determine whether the NRC approved guidance, provided in NEI 99-02, "Regulatory Assessment PI Guideline," Rev. 0 was properly implemented. Verification included the data collecting and reporting process, PI definitions, data reporting elements, calculational methods, definition of terms, and use of clarifying notes. The inspectors conducted interviews and reviewed the documents listed below:

- "Desktop Instructions: NRC Performance Indicators," Rev. 2 which provided station wide guidance for implementing the PI collection and reporting process
- April to June 2000 quarterly PI submittal
- July 2000 PI documentation and data review forms
- Various station logs and maintenance/testing documents
- Independent Safety Evaluation Group (ISEG) Activity Summary for June 2000
- EP-16, "NRC EPP Performance Indicator Instructions," Rev. 0

b. Issues and Findings

The inspectors determined that the PI collection and reporting process was generally consistent with NEI 99-02. Appropriate processes and responsibilities were implemented. Notwithstanding, the inspectors identified several issues which had the potential to result in inaccurate PI reporting as listed below. In each case, the issue was discussed with the Performance Indicator Licensing Engineer and appropriate corrective action was initiated to resolve the issue.

- The Unit 1 RCS Specific Activity TS Limit data element was incorrect. For the period April to June 2000, Beaver Valley reported 0.35 microcuries/gram I-131 which is the TS limit. However, a more restrictive administrative limit of 0.20 microcuries/gram I-131 had been established (Basis for Continued Operation (BCO) 1-00-004) to assure operability pending approval of the associated TS amendment request. The PI data collection process failed to address BCOs (CR

00-2611). The licensee agreed that the more restrictive administrative limit should be reported for this PI and planned to make this correction with the next quarterly PI report. The revision did not change significance (color) of the PI.

- The process for identifying Unplanned Power Changes initiated less than 72 hours following discovery of an off-normal conditions was deficient. The data collection engineer considered that if a deficiency tag had been written for a minor degraded material condition (that did not make a component inoperable) greater than 72 hours prior to an unexpected failure by that deficiency, requiring an immediate power reduction exceeding 20 percent power, the transient would be considered planned. The PI was intended to exclude problems which got worse gradually, but not sudden changes in material condition which forced a plant transient. Following further discussions, the PI Licensing Engineer informed the inspectors that the data collection process would be revised to include this type of event in the reported PI. The inspectors reviewed the past 6 months data for this PI and identified no discrepancies.

- The definition of “Timely” for event classifications and protective action recommendations (PAR) contained in EP-16 differed from NEI 99-02. The PI data collection process required the EP classification to be made within 15 minutes of identification of an initiating event. NEI 99-02 required classification within 15 minutes after plant parameters reach an emergency action level. The PI process required a PAR within 15 minutes of identification of an initiating event (i.e. General Emergency Declaration, events causing an upgraded PAR, etc.). NEI 99-02 required a PAR within 15 minutes of data availability. The difference in definitions could result in the licensee reporting more timely event opportunities than actually achieved. Condition report 00-2731 was initiated and a frequently asked question was submitted to NEI to resolve the inspectors’ concern.

The inspectors reviewed a recent PI process assessment performed by the ISEG. The purpose of the assessment was (1) to validate the methods used by site personnel to obtain data for the development of PIs, and (2) to verify the PI data. The assessment produced several recommendations directed toward reducing the unavailability time periods charged for safety system unavailability (SSU). However, the assessment did not identify any of the issues listed above which could lead to inaccurate PI reporting (including the incorrect Auxiliary Feedwater SSU PI data discussed in section 4OA1.1).

4OA3 Event Follow-up

.1 Unit 1 Trip Due To Main Turbine Electro Hydraulic Control Failure

a. Inspection Scope

On July 5, 2000 at 1:10 p.m., Unit 1 automatically tripped from 100 percent power. A main turbine EHC system failure caused the four turbine throttle valves to shut, which resulted in an automatic reactor trip (CR 00-2272). 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 emergency operating procedures, 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. Surveillance tests on the 1-1 emergency diesel generator and the control room emergency bottled air pressurization system were in progress at the time of the trip. The inspectors determined that these surveillances did not cause the event and that operators safely discontinued the surveillances and restored the equipment to appropriate standby configurations. 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. The inspectors determined that the conditional core damage probability was very low (approximately 2E-6) and that no additional NRC reactive response was necessary.

b. Issues and Findings

No significant findings were identified.

.2 (Closed) Licensee Event Report (LER) 05000334(412)/2000-001: Inadequate Guidance Provided to Operators Regarding Post-Design Basis Accident Operation of Supplemental Leak Collection and Release System.

a. Inspection Scope

On January 21 during a condition report investigation, Operations department personnel determined that Unit 1 and 2 operators did not have sufficient guidance to ensure that the supplemental leak collection and release system (SLCRS) would be operating following an accident. The inspectors reviewed the event report, evaluated the risk significance of the event, and assessed the adequacy of the corrective actions.

b. Issues and Findings

The inspectors determined that design requirements of the SLCRS system were not incorporated into plant emergency operating procedures (EOPs).

The SLCRS or primary auxiliary building ventilation system provides two design functions: 1) process engineered safety feature leakage following a loss of coolant accident (LOCA) such that 10 CFR 100 radiation exposure limits are not exceeded; and

2) provide cooling to safety related motors during design basis environmental conditions. Unit 1&2 SLCRS fans do not have an automatic start feature and therefore rely on operator action to start the fans during an event unless the fan was already in service. However, the Unit 1&2 emergency operating procedures did not include steps to either verify or initiate SLCRS fan operation following a design basis accident. In addition, there are no requirements to maintain the fans in service during routine plant operation. Therefore, the licensee concluded that operators did not have sufficient guidance to ensure that the SLCRS fans would be in operation following a LOCA. The licensee concluded the cause of the event was failure to translate SLCRS design requirements into procedures.

10 CFR 50 Appendix B, Criterion III, "Design Control" requires that "measures shall be established to assure ... the design basis ... for systems and components ... are correctly translated into specifications, drawings, procedures, and instructions." Contrary to the above, the design requirements for manual operation of the SLCRS were not incorporated into EOPs and therefore, was a violation of 10 CFR 50 Appendix B Criterion III. The violation is being treated as a Non-Cited Violation, consistent with Section VI.A of the Enforcement Policy, issued May 1, 2000 (65 FR 25368). **(NCV 05000334(412)/2000-006-01)**

The corrective actions included various training and revising the emergency operating procedures. The corrective actions were adequate to address the problem, however, the inspectors identified two areas that were not fully addressed. The potential existed that the SLCRS fan could fail after a completion of the revised EOP step. A fan failure at this time could affect room cooling for various safety related motors and design accident dose consequence calculations. The licensee was evaluating this concern through the corrective action program (CRs 00-2333).

Safety Significance

Using the SDP phase 1 analysis, the inspectors determined that the issue required a phase 2 risk analysis due to the event affecting two reactor safety cornerstones (mitigating systems and barrier integrity). The mitigating systems cornerstone was affected due to SLCRS providing a cooling function for the Units 1 and 2 HHSI systems, Unit 1 low head safety injection system, Unit 1 auxiliary feedwater system, and Unit 1 quench spray system. The barrier integrity cornerstone was affected since SLCRS provides the radiological barrier function for the auxiliary building (which in accordance with the SDP was considered part of the containment barrier). The results of the phase 2 analysis for Units 1 and 2 was a GREEN finding. Engineers determined that although temperatures would increase in the rooms containing mitigating equipment, operators would have sufficient time (greater than 15 hours) to identify the problem prior to equipment failure. Therefore, the event had very low safety significance (GREEN finding).

.3 (Closed) LER 05000334/2000-002 and 2000-002-01: Condition Outside Design Basis for One Train of River Water System Inoperable. This event was discussed in NRC Inspection Report Nos. 50-334(412)/00-01 and 00-02, and NRC Notice of Violation letter dated May 3, 2000. No new issues were revealed by the LER. This LER was closed during an onsite review.

4OA4 Cross-cutting Issues

Problem Identification and Resolution Problems

a. Inspection Scope

The inspectors observed or reviewed several maintenance activities during which performance problems occurred (Sections 1R13.1, 1R19, 1R22.1). The inspectors further reviewed the corresponding corrective actions to determine whether the action was appropriate to address the specific performance problems. Additionally, the inspectors reviewed a self assessment on the PI Collection and Reporting Process to determine whether the self assessment was effective in identifying deficiencies similar to those identified by the NRC during this inspection period (Section 4OA1.3).

b. Issues and Findings

On several occasions station personnel either did not initiate CRs for conditions adverse to quality, incorrectly or incompletely evaluated causes, or assigned incorrect priorities to resolve problems. Condition reports were not written for EHC system post-maintenance testing deficiencies and unnecessary emergency diesel generator unavailability until repeated questioning by the inspectors (CRs 00-2592 and 00-2628).

Station personnel initiated a category 2 CR (CR 00-2216) to evaluate a miscalibration of power range nuclear instrument N42 (see Section 1R22.1). Category 2 CRs address significant conditions adverse to quality, requiring the apparent root cause and extent of condition to be determined. The inspectors determined that the category 2 priority assignment and initial corrective actions were appropriate. However, the inspectors concluded that the causal analysis and corrective actions were incomplete in that they did not address double verification errors during data transcription or whether technicians sufficiently questioned unexpected equipment response during the calibration MSP. The inspectors discussed these observations with the Corrective Action Program Manager who subsequently reopened the CR 00-2216 investigation and initiated CR 00-2755 to address the incomplete investigation.

Station personnel initiated a category 3C CR (CR 00-2244) to evaluate miscalibration of power range nuclear instrument N44 (see Section 1R22.1). Category 3C CRs address conditions adverse to quality for which the cause is well understood and corrective actions are complete. No cause determination or further corrective action is required. The inspectors determined that CR00-2244 mischaracterized the cause as drift and that corrective actions did not address the cause of the problem. Resetting the detector voltage without additional monitoring or adjustment of the surveillance interval did not evaluate or resolve instrument drift. The inspectors noted that 2MSP-2.06-I specifically required the as left nuclear instrument detector voltage to be reverified after locking the adjustable potentiometer in place. Probable failure mechanisms included either an ineffective potentiometer locking mechanism or human error in setting the detector voltage. The inspectors discussed this observation with the Instrumentation and Control Department Manager and CRs 00-2591 and 00-2638 were initiated to address these concerns.

An assessment of NRC Performance Indicator Process implementation, performed by the ISEG, did not identify several readily apparent PI process or reporting errors (see Section 4OA1.3). Condition report 00-2788 was initiated to evaluate the inspectors' overall concern regarding incomplete problem identification and resolution.

4OA6 Management Meetings

.1 Unit 1 Reactor Vessel Pressurized Thermal Shock Meeting

On July 25-27, 2000, Mr. H. Woods and other NRC staff personnel met with Mr. F. von Ahn and other FENOC personnel to discuss information which may be pertinent to revision of the current Pressurized Thermal Shock (PTS) rule (10 CFR 50.61). The meeting also included a tour of the Beaver Valley Simulator to review PTS relevant controls/indications and demonstrations of PTS relevant scenarios.

.2 Revised Oversight Process Public Meeting

On July 27, 2000, Mr. John Rogge, Chief, Reactor Projects Branch 7 and other NRC staff personnel conducted a public meeting at the Beaver County Courthouse, Beaver, Pennsylvania, to discuss the NRC's revised Reactor Oversight Process which became effective April 2, 2000.

.3 Exit Meeting Summary

The inspectors presented the inspection results to Mr. Lew Myers and other members of licensee management at the conclusion of the inspection on August 23, 2000. The licensee acknowledged the findings presented.

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

ITEMS OPENED, CLOSED AND DISCUSSED

Opened/Closed

05000334/2000-006-01	NCV	Failure to incorporate supplemental leak and collection and release system design requirements into emergency operating procedures (Section 4OA3.2)

Closed

05000334(412)/2000-001	LER	Inadequate Guidance Provided to Operators Regarding Post-Design Basis Accident Operation of Supplemental Leak Collection and Release System (Section 4OA3.2)
0500034/2000-002 & 2000-002-01	LER	Condition Outside Design Basis for One Train of River Water System Inoperable (Section 4OA3.3)

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
BCO	Basis for Continued Operation
CFR	Code of Federal Regulations
CR	Condition Report
EDG	Emergency Diesel Generator
EHC	Electro Hydraulic Control
EOP	Emergency Operating Procedure
FENOC	FirstEnergy Nuclear Operating Company
gpm	gallons per minute
HHSI	High Head Safety Injection
ISEG	Independent Safety Evaluation Group
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MR	Maintenance Rule
MSP	Maintenance Surveillance Procedure
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
NSS	Nuclear Shift Supervisor
ODCM	Offsite Dose Calculation Manual
OM	Operating Manual
OPDT	Over Pressure Delta Temperature
OST	Operations Surveillance Test
OTDT	Over Temperature Delta Temperature
PAR	Protective Action Recommendation
PI	Performance Indicator
PM	Preventive Maintenance
PMT	Post-Maintenance Test
PRNI	Power Range Nuclear Instrument
PTS	Pressurized Thermal Shock
RCA	Radiologically Controlled Area
RCS	Reactor Coolant System
REMP	Radiological Environmental Monitoring Program
RPS	Reactor Protection System
SDP	Significance Determination Process
SLCRS	Supplemental Leak Collection and Release System
SSC	Structures, Systems, and Components
SSU	Safety System Unavailability
SW	Service Water
TM	Temporary Modification
TS	Technical Specifications
WO	Work Order

ATTACHMENT 1

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety	**Radiation Safety**	**Safeguards**
• Initiating Events	• Occupational	• Physical Protection
• Mitigating Systems	• Public	
• Barrier Integrity		
• Emergency Preparedness		

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.