October 17, 2001

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 50-334/01-08, 50-412/01-08

Dear Mr. Myers:

On September 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 October 5, 2001, 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 one issue of very low safety significance (Green). This issue was determined to involve a violation of NRC requirements. However, because of the low safety significance and because the issue was entered into your corrective action program, the NRC is treating the issue as a Non-Cited violation, in accordance with Section VI.A of the NRC's Enforcement Policy. If you deny the Non-Cited violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, within 30 days of the date of this inspection report, 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.

Since September 11, 2001, Beaver Valley Power Station has assumed a heightened level of security based on a series of threat advisories issued by the NRC. Although the NRC is not aware of any specific threat against nuclear facilities, the heightened level of security was recommended for all nuclear power plants and is being maintained due to the uncertainty about the possibility of additional terrorist attacks. The steps recommended by the NRC include increased patrols, augmented security forces and capabilities, additional security posts, heightened coordination with local law enforcement and military authorities, and limited access of personnel and vehicles to the site.

The NRC continues to interact with the Intelligence Community and to communicate information to FirstEnergy Nuclear Operating Company. In addition, the NRC has monitored maintenance and other activities which could relate to the site's security posture.

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/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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 50-334/01-08; 50-412/01-08
Attachments: 1) NRC Temporary Instruction 2515/145 Reporting Requirements
2) Supplemental Information

cc w/encl: L. W. Pearce, Plant General Manager
R. Fast, Director, Plant Maintenance
F. von Ahn, Director, Plant Engineering
R. Donnellon, Director, Projects and Scheduling
M. Pearson, Director, Nuclear Services
T. Cosgrove, Manager, Nuclear Regulatory Affairs
J. A. Hultz, Manager, Projects and Support Services, FirstEnergy
M. Clancy, Mayor, Shippingport, PA
Commonwealth of Pennsylvania
State of Ohio
State of West Virginia
R. Calvan, Regional Director, FEMA Region III

Distribution w/encl: Region I Docket Room (with concurrences)
D. Kern, DRP - NRC Resident Inspector
H. Miller, RA
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N. Perry, DRP
T. Haverkamp, DRP
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D. Loveless, OEDO
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L. Burkhart, PM, NRR
R. Schaff, Backup PM, NRR

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REGION I

Docket Nos. License Nos.	50-334, 50-412 DPR-66, NPF-73
Report Nos.	50-334/01-08, 50-412/01-08
Licensee:	FirstEnergy Nuclear Operating Company
Facility:	Beaver Valley Power Station, Units 1 and 2
Location:	Post Office Box 4 Shippingport, PA 15077
Dates:	August 12 - September 29, 2001
Inspectors:	D. Kern, Senior Resident Inspector G. Wertz, Resident Inspector R. Musser, Senior Resident Inspector, Region II C. Smith, Resident Inspector J. McFadden, Health Physicist J. Laughlin, Operations Engineer H. Gray, Senior Reactor Inspector F. Jaxheimer, Reactor Inspector
Approved by:	J. Rogge, Chief, Projects Branch 7 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000334-01-08, IR 05000412-01-08, on 08/12 - 09/29/2001; FirstEnergy Nuclear Operating Company; Beaver Valley Power Station; Units 1 & 2. Surveillance Testing.

The inspection was conducted by resident inspectors, a regional health physics inspector, two regional engineering inspectors, and two emergency preparedness inspectors. The inspection identified one Green finding, 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: Mitigating Systems

- **Green** The inspectors identified a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion XVI "Corrective Action," for failure to implement effective corrective measures to preclude repeated misperformance of safety-related procedures including Unit 1 Operating Surveillance Test (OST)-36.2, "Diesel Generator No. 2 Monthly Test," Rev. 32. This problem reflected ineffective problem resolution and human performance deficiencies. Operator fatigue was a contributing factor to the degraded human performance.

  The finding was of very low safety significance because the emergency diesel generator procedure performance errors did not represent an actual loss of safety function. (Section 1R22)

B. Licensee Identified Violations

No violations were identified.

Report Details

SUMMARY OF PLANT STATUS: Unit 1 began this inspection period at 100 percent power. The plant shut down on September 1 to begin the 14th refueling outage (1R14) and remained shutdown through the rest of the inspection period. The reactor was in Mode 5 (cold shutdown) at the close of the inspection period.

Unit 2 began this inspection period at 2598 megawatts thermal, which is 98 percent of rated power. The unit was operating at less than 100 percent indicated power due to a concern that the feedwater (FW) flow venturis may indicate lower than actual flow (see NRC IR Nos. 50-334(412)/01-07). This could cause indicated reactor power to be less than actual reactor power. Engineers concluded that the FW flow inaccuracy caused reactor power to indicate 1.5 percent lower than actual power. On September 9, 2001, operators raised indicated reactor power to 2612 megawatts thermal, which is 98.5 percent of rated power. Due to the FW flow inaccuracy, 2612 megawatts thermal indicated power corresponds to 2652 megawatts thermal actual power which is 100 percent of rated power. The unit remained at full power through the end of the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignments

.1 Unit 1 Circulating Water System and Cooling Tower Pre-Outage Maintenance

a. Inspection Scope

The inspectors performed a partial system walkdown of the Unit 1 circulating water system including the cooling tower. The inspectors recognized that pre-outage maintenance being performed on the cooling tower had the potential to affect plant operation or result in an initiating event. The inspectors reviewed Operating Manual (OM) Figure Number 31.1, “Circulating Water System,” Rev. 9, and Technical Manual 8700-04.025-0172, “Natural Draft Hyperbolic Cooling Tower,” Rev. K, to determine proper equipment alignments. In addition, the inspectors reviewed the ongoing pre-outage work on the cooling tower with the responsible maintenance supervisor and system engineer and evaluated the impact on system operation.

b. Findings

No findings of significance were identified.

.2 Unit 2 Turbine Driven Auxiliary Feedwater System

a. Inspection Scope

The inspectors performed a partial system walkdown of the Unit 2 Turbine Driven Auxiliary Feedwater (AFW) system. The AFW system is a risk important mitigating system for emergency decay heat removal of the reactor coolant system. The inspectors reviewed OM Figure Number 21-2, “AFW Pump Steam and Residual Heat Release,” Rev. 14, and

OM Figure Number 24-3, “Auxiliary Feedwater System,” Rev. 8, prior to performing a field verification for proper equipment alignment. The inspectors observed various AFW control room indicators and reviewed the system alignment with the control room operators in order to verify as-found field conditions.

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 identified the following risk significant areas:

- Unit 1 Process Instrument Room (Fire Area CR-4)
- Unit 1 Containment Building (Fire Area RC-1), 692 and 718 foot levels
- Unit 1 Containment Building (Fire Area RC-1), 735 foot level
- Unit 1 Containment Building (Fire Area RC-1), 763 foot level

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.

1RO8 Inservice Inspection Activities

a. Inspection Scope

The inspected areas included reactor coolant system (RCS) head penetration piping, reactor vessel nozzle to piping welds, eddy current testing of steam generator tubes, emergency core cooling system (ECCS) connections to the RCS, and flow accelerated corrosion (FAC) detection and mitigation including significant non-code repairs.

To evaluate steam generator tube integrity, the inspector reviewed: the licensee’s commitments regarding steam generator repair criteria (tube plugging & sleeving); the eddy current (ECT) and in-situ pressure testing program scope and procedures; foreign material exclusion (FME) controls; steam generator sludge chemistry characterization results from Unit 1 refueling outage 13; refuel outage 14 (1R14) cleaning process/results; and the previous operating cycle performance (Primary to Secondary leakage). The 1R14 steam generator outage activities including eddy current testing scope were compared to the appropriate Electric Power Research Institute and NRC guidelines.

The licensee’s activities performed in response to NRC Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” were inspected against the requirements of Temporary Instruction (TI) 2515/145, “Circumferential Cracking of RPV Head Penetration Nozzles.” The description of the inspection scope and results is in section 4OA5 as specified by the TI.

RCS cold leg weld ultrasonic examination results were inspected. This examination was follow-up of a previous inservice inspection (ISI) indication at weld location DLW-LOOP3-7-S-02. The inspection method and acceptance criteria for this weld indication were reviewed.

The radiographs of reactor coolant pump Design Change Package (DCP) 2386 were inspected. Several 2 inch, schedule 160 butt weld radiographs were evaluated to assess if the radiographs met ASME Code and radiographic procedural requirements and that acceptance criteria were appropriate. Radiographs for two recently performed safety injection system welds, SI-75-2-F-6A and 60-1A-F-7A, were also reviewed.

The inspectors verified that plant staff was aware of significant industry ISI operating experience items and that an assessment of applicability to Beaver Valley Unit 1, was performed.

The inspectors reviewed the extent that measurements were taken and evaluated for FAC. The mitigation strategy for identified FAC conditions was compared with EPRI and NRC guidelines.

The reduction of scope of ISI inspections from that originally planned for this refueling outage was compared to the American Society of Mechanical Engineers Code, Section XI for ISI and Beaver Valley ISI program requirements to determine if the deferment of specific inspections was appropriate.

Inspectors verified the licensee had identified ISI problems at an appropriate threshold and entered them into the corrective action program. The type and scope of the corrective actions for a sample of four ISI related Condition Reports (CRs) were verified.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors evaluated Maintenance Rule (MR) implementation for the issues 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 Code of Federal Regulations (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. For selected systems, the inspectors observed maintenance rule steering committee (MRSC) meetings to determine whether system performance was properly dispositioned for MR category (a)(1) or (a)(2) performance monitoring. The following were reviewed:

- The inspectors observed the MRSC meeting of August 24 which concurred with the system engineer’s recommendations to place the Unit 1 instrument air (IA) system in MR category (a)(1). The (a)(1) recommendation was appropriate because a failure of a purge valve on the IA dryer on June 22 resulting in a loss of station instrument air and subsequent manual reactor trip (see NRC Inspection Report Nos. 50-334(412)/01-06). The inspectors reviewed the recommended goals for returning the IA system to MR category (a)(2).

- Unit 1 480 volt (V) station service system goals and appropriateness of corrective actions for system in (a)(1) status.

- Unit 2 primary component cooling and neutron shield tank cooling system goals and appropriateness of corrective actions for system in (a)(1) status.

- Unit 2 480V station service system goals and appropriateness of corrective actions for system in (a)(1) status. The inspectors reviewed current system performance with the system engineer and discussed the risk basis of the criteria established for determining the length of time the system should remain in (a)(1) status.

b. <u>Findings</u>

No findings of significance were identified.

1R13 <u>Maintenance Risk Assessment and Emergent Work Control</u>

a. <u>Inspection Scope</u>

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 the following routine planned maintenance and emergent work:

- On August 6, Units 1 and 2 implemented Technical Specification (TS) Amendment Nos. 239 and 120 respectively, which revised over 40 reactor trip system and engineered safety feature actuation system setpoints, based upon a revised thermal design procedure. The TS amendment implementing instructions authorized the licensee to revise the individual setpoints over a 3-month period as the associated periodic channel functional tests came due. The safety evaluation for the amendment reviewed the collective effect of the setpoint changes, but did not focus on individual setpoints alone. The inspectors determined that four individual setpoint changes would increase margin between the trip actuation settings and the plant safety analysis limit. The remaining revisions would reduce the safety margin. The inspectors verified that the four setpoints which increased safety margin were implemented first, prior to implementing any of the remaining setpoint changes. Based on this review, the inspectors verified that Units 1 and 2 would remain within their respective safety analysis during implementation of the remaining 35+ trip actuation setpoint changes, regardless of the order in which they are implemented. The risk associated with implementing the setpoint revisions was effectively managed.

- On August 20, technicians performed repairs to oil circuit breaker (OCB) 94 which provides 138 kilovolts (kV) to the ‘2B’ system station service transformer. This transformer is one of the two independent offsite electrical supplies. The work activity was planned to repair OCB-94 in the closed or energized condition. The repairs consisted of replacement of a hydraulic pump and high pressure relief valve. The inspectors reviewed the work plan in advance of the maintenance activity because the repair would render OCB-94 incapable of closing should it inadvertently open. The inspectors observed the pre-evolution briefing and field maintenance performed to verify plant risk was properly addressed.

- In order to maximize Unit 1 electrical generation until the start of 1R14, operators implemented an average RCS temperature (Tavg) reduction strategy. This reduction in Tavg allowed the near end-of-cycle fuel depletion reactivity loss to be compensated for with positive reactivity addition due to the reduction in reactor coolant temperature. The inspectors reviewed the coastdown evaluation contained in technical evaluation report (TER) 13802, “Evaluation of Tavg/Power Coastdown for End of Cycle 14,” Rev. 0, prior to the beginning of plant coastdown on August 22 in order to assess its impact on plant operation. Engineers had evaluated continued plant operation with a reduction in Tavg of 10 degrees Fahrenheit (°F) from 576.4 °F to 566.4 °F. Specific operational criteria were incorporated into OM 1OM-52.4.B, “Load Following,” Rev. 21. The inspectors reviewed 1OM-52.4.B and 1OM-54.4C1-3, “Daily Heat Balance,” Rev. 9, and monitored affected plant parameters daily during the coastdown in order to verify that plant operation was within the specified criteria. See Section 1R14 for additional information.

b. <u>Findings</u>

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions

a. Inspection Scope

The inspectors reviewed human performance during the following non-routine plant evolutions, to determine whether personnel performance caused unnecessary plant risk or challenges to reactor safety. The inspectors reviewed the evolutions in accordance with the requirements listed in NPDAP 8.23, “Infrequently Performed Tests or Experiments,” Rev. 5, and the station procedures and NRC Information Notice listed below:

- As a result of the Unit 1 planned Tavg coastdown, the mismatch between Tavg and the reference RCS temperature (Tref) would increase as Tavg decreased. In order to avoid operational problems with nonsafety-related rod control and steam dump systems, which utilize a Tavg-Tref mismatch or error signal, engineers determined that Tref should be rescaled twice during the coastdown. First, Tref would be rescaled to 571.2 °F when Tavg reached 573.7 °F, then Tref would be rescaled to 566.2 °F when Tavg reached 568.7 °F. The inspectors observed a partial performance of the Tref rescaling work. Following the completion of the work, engineers determined that the Tref signal to the steam dump control system was incorrectly rescaled to the 566.2 °F value instead of the 571.2 °F value. The inspectors reviewed the effect of the misadjustment of Tref to the steam dump control system had on plant safety. The event was entered into the corrective action program as CR 01-5276.

- On September 11, 2001, in response to terrorist attacks within the United States, the NRC recommended that nuclear power plants establish increased security awareness (Security Level III advisory) as described in NRC Information Notice (IN) 98-35, “Threat Assessments and Consideration of Heightened Physical Protection Measures.” The inspectors interviewed station personnel, performed plant security station walkdowns, and observed various activities to verify enhanced station security measures were established consistent with the station Security Plan and NRC IN 98-35. Additionally, the inspectors verified that Unit 1 shutdown safety was properly maintained as work schedules, outage work scope, and contractor oversight practices were revised to address the potential security threat.

- On August 29, the second of two Unit 2 control rod drive mechanism (CRDM) shroud cooling fans (2HVR-FN202B1) to the ‘B’ cooling air duct failed (the CRDM shroud cooling system has three cooling air ducts [‘A’, ‘B’ and ‘C’] with two cooling fans in parallel. Normal operation consists of one fan in service on each of the three air ducts). Operators determined that the ‘B1' fan tripped on overcurrent relay protection. The other fan in the ‘B’ air duct (the ‘B2' fan) was disabled in April due to an electrical ground fault of the fan motor. Operators appropriately entered alarm response procedure (ARP) 2OM-44C.4.AAB, “CRDM Shroud Fan Auto-Start/Auto-Stop,” Rev. 5. which provided specific guidance for actions should both fans in a single CRDM cooling duct fail. The concern for operation with this condition is that elevated CRDM temperatures due to a potential loss of cooling could result in overheating of the affected CRDM and the potential for multiple control rods to unexpectedly insert into the reactor. The resulting reactivity change could cause excessive neutron flux peaking in the reactor core or a reactor trip which is an initiating event. The inspectors reviewed the ARP including the vendor guidance with respect to CRDM temperature monitoring and resulting action. The inspectors noted that engineers developed additional operational guidance, which was incorporated into a subsequent revision of the ARP, and detailed repair plans using industry information for a similar situation at another nuclear plant.

b. Findings

No findings of significance were 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. In addition, where a component was determined to be inoperable, the inspectors verified the TS limiting condition for operation implications were properly addressed.

- On August 28, 1VS-D-4-4A, Charging Pump Cubicle Exhaust Damper, one of two parallel dampers providing an exhaust ventilation cooling path for the three charging pump cubicles, was discovered in the closed position instead of the normally open position. The inspectors reviewed the licensee's operability determination that concluded that the Unit 1 charging pumps remained operable with one of the two parallel dampers in the closed position (CR 01-5387).

- On August 10, Unit 2 operators determined that Anticipated Transient Without Scram (ATWS) Mitigation System Actuation Circuitry (AMSAC) was not within design parameters. The AMSAC is designed to enable above 40 percent plant power to limit the effects of an ATWS. Accident analyses do not credit AMSAC for core protection below 70 percent power. Inaccuracies in the FW flow venturi, discovered in July (See NRC Inspection Report 50-332(412)/01-07), resulted in the AMSAC not being enabled until approximately 41 percent plant power. Maintenance engineers documented this condition in CR 01-4974. The inspectors reviewed the design basis requirements of the AMSAC in order to verify that its safety function was maintained. The AMSAC setpoint was successfully re-calibrated on September 23 in accordance with (iaw) Work Order (WO) 01-017786-000 (See Section 1R19 for post-maintenance testing results).

b. Findings

No findings of significance were 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:

- The Unit 1 ‘A’ Low Head Safety Injection (LHSI) pump motor was refurbished by the motor vendor iaw WO 00-001713-005 and the specifications of purchase order 7069306. The pump was successfully post-maintenance tested iaw the requirements of 1OST-11.14A, “LHSI Full Flow Test,” Rev. 9, on September 15. The inspectors observed portions of the maintenance activities performed and reviewed the WO, purchase order, and PMT.

- As a result of past performance problems, captured in CR 00-3104, the Unit 1 120V alternating current (AC) vital electrical distribution bus uninterruptible power supply (UPS) unit was replaced iaw DCP 2422, “Replace UPS Units for Vital Bus #3 and #4,” Rev. 0, during 1R14. The inspectors discussed the proposed corrective action (UPS replacement) with the system engineer prior to the outage due to the numerous performance problems noted on the 120V AC vital bus. The inspectors reviewed DCP 2422 and temporary modification 1-01-013, which provided an alternate power supply to vital bus #3 while the UPS unit was removed from service for replacement, and observed installation activities. Post installation acceptance testing of the new UPS unit was performed satisfactorily iaw test procedure IT-38-2422-1, “Vital Bus III INV-VITBUS-3 Functional Test,” Rev. 0. The inspectors observed the DCP training which included a field demonstration of the UPS operation by the vendor technical representative and detailed training materials.

- AMSAC calibration was performed iaw the specifications of 2LCP-24-AMSAC-I, “AMSAC Functional Test and Calibration,” Rev. 7, following identification of FW flow venturi inaccuracies (See Section 1R15 above for additional details). Revised plant power versus turbine impulse pressure calibration constants were developed and specified in TER 13813, “Turbine Impulse Pressure Instrument Loops Rescaling,” Rev. 0. The inspectors reviewed the completed TER and calibration procedure, and discussed the calibration activity with maintenance engineers in order to verify that AMSAC was returned to its design 40 percent power enable setpoint.

- As a result of past problems (including a forced unit shutdown in 1998) with the station 120V safety-related battery cells maintaining their individual cell float voltage within specified range, individual cell equalizers (ICE) were installed on batteries 1-1 and 1-3 during 1R14. The ICEs provide an alternative current path for each cell in the battery bank in order to allow individual battery cells to charge to a specific voltage. The ICEs will prevent battery cell voltage equalizing charges from overcharging or undercharging individual cells and should increase the maintainability of the battery banks. The ICEs were installed iaw WO 01-002136-000 and TER 13860, “Installation of Individual Cell Voltage Equalizer Units,” Rev. 0. The inspectors observed the installation and reviewed the post- installation testing performed iaw Beaver Valley Test (BVT) 1BVT 01.39.01(03), “Station Battery [BAT-1(3)] Service Test,” Rev. 4.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors observed selected reactor shutdown, refueling, outage maintenance, and reactor startup activities to determine whether shutdown safety functions (e.g., reactor decay heat removal, reactivity control, electrical power availability, reactor coolant inventory, spent fuel cooling, and containment integrity) were properly maintained as required by TSs and license conditions. Specific performance attributes evaluated, included configuration management, communications, instrumentation accuracy, and identification and resolution of problems. The inspectors closely evaluated configuration and inventory control during periods of reduced reactor coolant system inventory due to the associated increase in shutdown risk. Specific activities evaluated included:

- 1OST-51.4.D, “Cooldown From Mode 4 to Mode 5,” Rev. 24
- 1RP-3.16, “Refueling Procedure Core Unload,” Rev. 1
- 1RP-3.24, “Refueling Procedure Core Reload,” Rev. 1
- The inspectors observed steam generator chemical cleaning activities which removed a total of approximately 6000 pounds of material.
- The inspectors observed CRDM penetration inspections which were performed to determine whether Unit 1 had experienced penetration cracking and associated RCS leakage which was observed earlier this year at two other nuclear power plants.
- The inspectors observed the RCS draindown performed iaw 1OM-6.4.N, “Draining the RCS for Refueling,” Rev. 13. The inspectors focused on the adequacy of the reactor water level instrumentation in the control room and the temporary level indication installed in the containment building as instrumentation inaccuracies have hampered the operators ability to drain the RCS during past refueling outages.
- The inspectors reviewed the 1R14 Pre-Outage Shutdown Safety Review performed by the Nuclear Quality Assessment Section, Probabilistic Risk

Assessment Engineering Group and Unit 1 Operations. The inspectors reviewed the key safety functions associated with: 1) electrical power to the emergency bus; 2) decay heat removal; 3) boration and inventory control; and, 4) containment integrity. The inspectors also reviewed the RCS time to boiling (TTB) after noting that a recalculation by design engineering resulted in the TTB increasing from 21 to 64 minutes. The outage management team also questioned the 64 minute TTB and decided to verify the calculation prior to using it as the basis for any containment integrity changes (i.e., open the equipment hatch). In response to the inspectors questions, design engineers determined that the new TTB (of 64 minutes) was too long. Inaccurate assumptions had been used. CR 01-5796 was written to address this issue.

- Prior to reloading fuel assemblies into the reactor, containment integrity controls were required iaw 1OST-47.3D, "Verification of Administrative Closure Controls for Containment/Fuel Building During Refueling," Rev. 0. The inspectors reviewed the operating surveillance test (OST) which described the necessary actions for rapid closure of the containment equipment and personnel hatches and performed a walkdown of the containment hatches in order to verify that the administrative controls were in place as described in the OST.

- In response to an industry event in which a fuel assembly top nozzle separated from the fuel element during movement and fortuitously fell into its spent fuel pool location, engineers developed 1R14 outage plans to identify the susceptible fuel assemblies in the reactor and implement corrective actions prior to their movement into the fuel pool. The plan, outlined in CR 01-1709, involved installation of anchors in the top nozzles of nine (9) fuel assemblies to ensure mechanical integrity between the top nozzle and the fuel assembly. The inspectors reviewed the plan, including identification of susceptible fuel assembly types, and the licensee's controls to preclude future movement of susceptible assemblies.

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 as required by TSs.

- 1OST-36.5, "Emergency Switchgear Operation Test (Manual Transfer From Unit To System Station Service Transformer)," Issue 4, Rev. 1

- 1OST-36.2, "Diesel Generator No. 2 Monthly Test," Rev. 32

- 2OST-11.2, “Low Head Safety Injection Pump [2SIS*P21B] Test,” Rev. 17. A minor data collection difficulty was captured in CR 01-5145.

- 2OST-24.4, “Steam Turbine Driven Auxiliary Feed Pump [2FWE*P22] Quarterly Test,” Rev. 40. Minor steam leakage through the outboard turbine seal was documented in work request 01-5227 for resolution.

b. <u>Findings</u>

The inspectors determined that corrective actions taken to preclude recurrence of procedural violations and human performance errors during safety-related surveillance testing were ineffective. The safety significance of this finding was very low (Green) because the performance errors did not cause the emergency diesel generator (EDG) to become inoperable. Failure to correct a condition adverse to quality, misperformance of safety-related procedures, was a Non-Cited Violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action.”

On August 15, Unit 1 operators made two errors while performing 1OST-36.2, “Diesel Generator No. 2 Monthly Test,” Rev. 32. The local operator inadvertently skipped step 14 (adjust speed droop to 60) which adversely affected the EDG’s load carrying stability. A peer check failed to recognize this error. The reactor operator inadvertently skipped step 28 (close motor operated ground switch) which prevented the EDG output breaker from shutting and supplying electrical load. Human performance engineers reviewed the activity, identified causal factors and lessons learned, and briefed site personnel on their findings. The inspectors noted that the activity review and operator statements indicated that fatigue associated with routinely working overtime, was a contributing cause. The local operator and reactor operator had worked approximately 50 percent overtime during the month preceding this event. The inspectors discussed the issues of procedure usage, operator fatigue, and management oversight during the upcoming refueling outage with station management.

The inspectors previously identified that on three occasions in 2000, operators had inadvertently skipped steps while performing 1OST-36.2 (CR 00-2110) or performed steps out of order when operating the emergency response facility diesel generator (CR 00-2335). Corrective actions included operator training and use of various human performance tools, to reinforce management expectations for procedure adherence. The inspectors determined that the corrective actions were not effective in preventing recurrence of performance errors during safety-related procedures such as 1OST-36.2.

This issue had a credible impact on safety, in that failure to properly perform safety-related procedures can cause safety-related equipment to be unable to perform its design function. Failure to perform procedures as written could result in incorrect mitigating system configurations and actuation setpoints, which could adversely effect operability, availability, and reliability. The issue was evaluated using the phase 1 SDP for the Mitigation System cornerstone. The inspectors determined that the issue was of very low (Green) safety significance because the EDG procedure performance errors did not represent an actual loss of safety function.

10 CFR 50 Appendix B, Criterion XVI "Corrective Action," requires that for significant conditions adverse to quality, measures shall be taken to assure that the cause of the condition is determined and corrective action taken to preclude repetition. Contrary to the above, corrective action measures did not preclude repeated misperformance of 1OST-36.2. This violation is being treated as a NCV consistent with Section VI.A of the NRC Enforcement Policy. This issue was entered into the corrective action program as CRs 01-5112 and 01-6712 **(NCV 50-334/01-08-01)**.

Emergency Preparedness (EP)

1EP2 Alert and Notification System (ANS) Testing

a. Inspection Scope

The inspectors reviewed documentation regarding the siren system design and approval, system maintenance, and testing. The inspectors verified compliance with emergency plan (E-Plan) commitments and the guidance of NUREG-0654, Section II.E.

b. Findings

ANS Design:

A report entitled "Beaver Valley Power Station (BVPS) Site-Specific Offsite Radiological Emergency Preparedness Alert and Notification System Quality Assurance Verification," summarized the engineering design review used by the Federal Emergency Management Agency (FEMA) for approval of the BVPS ANS in December 1985. The report states that the evaluation performed sought to determine whether the siren system as designed, and supplemented by personal home alerting devices (PHADs) and route alerting could meet the ANS acceptance criteria. This report states that the physical means of alerting the public consists of 110 sirens, approximately 1200 PHADS (in Beaver County, PA, only), and route alerting by police and fire departments. The report goes on to say that due to the rugged terrain features within the Emergency Preparedness Zone (EPZ), there may be gaps or blind spots where the sirens may not attain the required decibel noise level, and thus PHADs and route alerting units were planned as "supplemental" alerting modes. It also refers to the PHADs as a "complementary" system which was installed at homes in sparsely populated areas or in "blind" spots of the audibility range of the pole-mounted sirens in Beaver County.

The E-Plan states that there are two types of sirens: 1) Large pole-mounted sirens, and 2) PHADs. Concerning PHADs, the E-Plan states, "In certain areas of the EPZ, the terrain makes it impossible to adequately notify everyone by use of the pole-mounted sirens. Some residents of the EPZ live outside the effective audible range of the sirens. Therefore, the utility has installed PHADs adjacent to the electric meter at each of these residences."

If the PHADs are integral (needed to fulfill function) to ANS, they must be periodically tested to verify operability. The inspectors questioned the adequacy of testing the PHAD system. Specifically, there was no approved testing procedure and the test consisted of several individuals listening for an indeterminate number of PHADs to sound, indicating that some devices received an activation signal, not that all 1200 devices were functional. Although the licensee stated that the PHADs were tested annually since about 1987, there was no testing documentation available. Additionally, the licensee had no feedback mechanism (either electronic from the devices during testing or resident feedback) to identify, evaluate, and correct PHAD deficiencies, nor was there any evaluation to determine if more PHADs were necessary based on population redistribution and/or new residential construction since 1985.

The inspectors noted from the documentation review that the PHADs, though characterized as a supplemental system, were: 1) a license commitment per the licensee's E-Plan, and 2) appeared to be relied on by FEMA as a necessary part of the ANS for system design approval. The licensee stated at the August 13 exit meeting that the PHADs were supplemental and, therefore, an enhancement, not necessary for alerting the public. Licensee management and the Beaver County Emergency Management Director reiterated this position in a final exit conference call on August 31. The licensee EP Manager also provided data based on 1980 census information which approximated the PHAD population coverage in the 10-mile EPZ at about 2.9 percent.

From the above, it was unclear whether the PHADs are integral to the ANS in order to achieve the function required by 10 CFR 50.47(b)(5) and related requirements of 10 CFR 50, Appendix E, Section IV.D.3. If the PHADs are integral to the ANS, there are also questions on the adequacy of testing and operability of each PHAD. Since 10 CFR 50.47(b)(5) is a risk significant planning standard (RSPS), there is a question as to whether this RSPS function would be met.

ANS Corrective Actions:

The March 2001 licensee Quality Assurance (QA) audit of the EP program identified ineffective corrective actions concerning the PHADs. Specifically, the 1998 QA audit had identified in CR 98-0481 that there was no procedure to formalize PHAD maintenance and testing, and associated documentation. The EP department had agreed to a corrective action (CA) to update procedure EP-7, "Alert Notification System Maintenance and Testing," to correct this deficiency. This CA was closed to another CR concerning the 1999 siren system update, but EP-7 was not updated to proceduralize PHAD maintenance and testing. Following another QA audit finding in 2001, which identified this oversight, the EP-7 revision was completed in April 2001 requiring testing/documentation of PHADs, administratively, but it lacked details as a test procedure.

The inspectors determined that this procedure revision only formalized the limited scope of test coverage described above and overall reflected an inadequate testing methodology. Specifically, there was no approved test procedure, and no defined acceptance criteria to assess operability of the 1200 PHADs, as of the inspection conclusion on August 31. This constituted a potential failure to correct a problem associated with RSPS 10 CFR 50.47(b)(5).

Summary:

The potential failure to meet RSPS 10 CFR 50.47(b)(5) for ANS coverage and the potential failure to correct a problem associated with an RSPS, are unresolved pending a determination by FEMA/NRC as to whether the PHADs are integral to the ANS function, or are a system enhancement. If the PHADs are determined to be integral to the ANS, then an adequate test would be necessary to show system operability. NRC will be obtaining information for FEMA related to these matters. **(URI 50-334; 50-412/01-08-02)**

1EP3 Emergency Response Organization (ERO) Augmentation Testing

a. Inspection Scope

The inspectors reviewed the licensee's commitments for ERO staffing and facility activation. Several training and qualification records were reviewed for newly qualified ERO members. Random records for previously qualified ERO members were also reviewed. Staff depth for key ERO positions was reviewed to ensure that sufficient numbers of responders were available. The procedure for initiating ERO call-in was reviewed and discussed with responsible licensee personnel. Documentation from pager tests and recent call-in drills was reviewed for ERO response timeliness and consistency. Condition reports addressing this area were reviewed to assess priority and effectiveness of corrective actions to assure operability and reliability of the notification process and system.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

The inspectors reviewed recent emergency plan and implementing procedure changes to determine if the changes resulted in a decrease in the effectiveness of the emergency plan. The licensee's 10 CFR 50.54(q) review process for plan changes was assessed.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

a. Inspection Scope

The inspectors reviewed corrective actions identified by the licensee in response to QA audits, surveillances, communication drills, drill reports, and regular self-assessments. CRs assigned to the EP department were also reviewed to determine the significance of the issues and to determine if repeat problems were occurring. The inspectors reviewed the reports for the 1999 and 2000 10 CFR 50.54(t) reviews to assess whether the reviews met the requirements and if any repeat issues were identified. CRs initiated after the July 2000 exercise and the associated corrective actions were reviewed for effectiveness and compliance with 10 CFR 50, Appendix E, Section IV.F.2.g, concerning the identification and correction of weaknesses and deficiencies.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Occupational Radiation Safety (OS)

2OS1 Access Control To Radiologically Significant Areas

a. Inspection Scope

The inspectors reviewed the effectiveness of access controls to radiologically significant areas. The inspectors toured the radiologically controlled area (RCA) including: various elevations of the primary auxiliary, fuel, and containment buildings of Unit 1 and the health physics (HP) access control point; the radiological work permit office; and the HP's room for radiation worker briefings in Unit 2.

During RCA walkdowns, the inspectors observed and verified the appropriateness of the radiological safety controls for active radiological work permits (RWPs) and evaluated the effectiveness of pre-job radiation safety briefings at the Unit 1 containment entry point on September 12 and 13, 2001. The inspectors reviewed; posting, labeling, and barricading (as appropriate) of; radiation, contamination and high radiation areas (HRAs), and the status of locked HRAs. The inspectors observed the dose-rate survey meter readings obtained by radiation protection technicians to verify the adequacy of various area postings. The inspectors also observed activities at the main RCA access control points to verify compliance with requirements for RCA entry and exit, wearing of dosimetry, and issuance and use of alarming radiation dosimeters.

The inspection included a review of the following outage RWPs, procedures, records, and documents to evaluate the adequacy of radiological controls:

- RWP 101-4020, In-Service Inspections,

- RWP 101-4040, Steam Generator Platform Support,
- RWP 101-4043, Repair/Replace Residual Heat Exchanger Pump,
- RWP 101-4047, Steam Generator Secondary Side Chemical Cleaning,
- RWP 101-4057, Reactor Coolant Pump Seal Inspection/Repair,
- RWP 101-4067, Control Rod Drive Mechanism Nozzle Inspections,
- Procedure RP 8.1, “Radiological Work Permit,” Rev. 14,
- 1R14 Daily exposure summaries for September 10, 11, 12, 13, and 14, 2001,
- Memorandum, D.F. Weitz to J. Fontaine, dated August 29, 2001, “Alpha monitoring requirements for 1R14 work activities,” and
- Outage handbook, September 2001, Unit 1 refueling outage, 1R14.

The inspection selectively examined problem reports (condition reports) for issues occurring between mid-June 2001 and September 12, 2001. The details of two CRs associated with worker and/or radiation protection technician performance errors or radiological protection concerns (CR Nos. 01-4409 and 01-5980), were reviewed. The review included an evaluation of the associated cause evaluations and corrective actions.

The review of the above cited documents and activities was against criteria contained in: 10 CFR 20.1201 (Occupational dose limits for adults), 20.1204 (Determination of internal exposure), 20.1208 (Dose equivalent to an embryo/fetus), Subpart F (Surveys and monitoring), 20.1601 (Control of access to HRAs), Subpart H (Respiratory protection and controls to restrict internal exposures in restricted areas), 20.1902 (Posting requirements), site TS 6.12 (HRA), and site procedures (identified above in this section).

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Control

a. Inspection Scope

The inspectors reviewed the effectiveness of ALARA (As Low As is Reasonably Achievable) planning and control. The inspectors observed pre-job ALARA briefings on September 11, 2001, for containment entries on RWP 101-4040 and on RWP 101-4030, and witnessed Site ALARA Committee meetings on September 10 and September 12, 2001. The following procedures, records, and documents were reviewed:

- Health Physics Manual, Appendix 11, “ALARA Program,” Rev. 2,
- Procedure RP 8.1, “Radiological Work Permit,” Rev. 14,
- Procedure RP 8.5, “ALARA Review Program,” Rev. 4,
- Comparison of actual versus estimated collective exposure for year-to-date forUnit 1 and 2,
- Pre-job ALARA reviews for RWPs 101-4020, -4040, -4043, -4047, -4057, and -4067,
- Minutes for sixteen Site ALARA Committee meetings conducted between July 6 to September 10, 2001,

- 2001 Man-Rem Budget Summary, and
- FirstEnergy Nuclear Operating Company Business Plan 2001 - 2005.

The review was against criteria contained in 10 CFR 20.1101 (Radiation protection programs), 10 CFR 20.1701(Use of process or other engineering controls), and site procedures (identified above in this section).

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator (PI) Verification

Occupation Exposure Control Effectiveness

a. Inspection Scope

The inspectors reviewed the reported PI data for occupational exposure control effectiveness from October 2000 through June 2001. Additionally, the inspectors reviewed selected records used by the licensee to identify occurrences involving HRAs, very HRAs, and unplanned personnel exposures for the time period from mid-June 2001 to early September 2001 against the applicable criteria specified in Nuclear Energy Institute (NEI) 99-02, “Regulatory Assessment Performance Indicator Guideline,” Rev. 0 and Rev. 1, to verify that all conditions that met the NEI criteria were recognized, identified, and reported as PI occurrences. The reviewed records included corrective action program records (condition reports) and RCA access control alarm reports.

b. Findings

No findings of significance were identified.

.2 Unplanned Power Changes per 7000 Critical Hours

a. Inspection Scope

The inspectors reviewed the Unit 1 and Unit 2 performance indicators for unplanned changes in reactor power of greater than 20 percent per 7000 hours of critical operation against the applicable criteria specified in NEI 99-02, to verify that all conditions that met the NEI criteria were recognized and identified as PI occurrences. Manual and automatic scrams are excluded from this PI. The inspectors verified accuracy of the reported data through reviews of monthly operating reports, shift operating logs, Licensee Event Reports (LERs) and additional records. The inspectors reviewed 12 months of reported data (July 2000 - June 2001) and the latest 3 months of collected data which has not yet been reported (July - September 2001).

b. Findings

The inspectors reviewed an April 21, 2001, Unit 2 downpower in detail to determine whether it was properly evaluated. On April 17, operators observed a ground on the 2-5 DC electrical supply bus. On April 21, technicians completed troubleshooting activities and localized the ground to the 125 volt control power breaker for 4 kilovolt electrical breaker 2A9, which supplied power to heater drain pump 2HDH-P21A. The Nuclear Shift Supervisor (NSS) contacted the load dispatcher and requested a window to perform a power reduction to approximately 40 percent to perform the breaker repair. The window could be April 21, 22, or the following weekend (April 28, 29). The NSS said Unit 2 was volunteering to “load follow” in place of another FirstEnergy power plant since system electrical demand was anticipated to be low. The load dispatcher determined that April 21 was acceptable for Unit 2 to perform a power reduction (“load follow”). Station personnel considered this downpower to be a “load follow” power reduction, performed at the request of the load dispatcher, and therefore not reportable under this PI. The licensee did not report this power reduction as an unplanned power change.

The inspectors questioned whether the April 21, 2001, Unit 2 power reduction had been properly evaluated for PI reporting. The inspectors noted that the licensee identified the specific degraded material condition, a grounded control power breaker for 2HDH-P21A, on April 21. The NSS then initiated a call to the load dispatcher to request a time period when Unit 2 could downpower to perform the repair. The NSS indicated that the need for the repair was not urgent, and the repair could wait until the following weekend (April 28-29) if necessary. The downpower was initiated on April 21, after receiving permission from the load dispatcher. The inspectors observed that the power reduction of greater than 20 percent, was initiated less than 72 hours following the discovery of the off-normal condition (ground on breaker for 2HDH-P21A), which required a power reduction to resolve. Additionally, the NSS, not the load dispatcher, initiated the request for a power reduction. The inspectors determined that the power reduction was performed for the purpose of resolving the degraded material condition, and not solely for the purpose of “load following”. CR 01-6679 was initiated and a frequently asked question was submitted to NEI to resolve the inspectors’ concern regarding assessment of this downpower for NRC PI reporting.

.3 Emergency Diesel Generator Safety System Unavailability

a. Inspection Scope

The inspectors reviewed the Unit 1 and Unit 2 PIs for safety system unavailability of the emergency alternating current power system. The inspectors verified the accuracy of the reported data for the past year (September 2000 - August 2001) through reviews of shift operating logs, various completed OST procedures, condition reports and maintenance rule system unavailability records. Performance indicator verification included observation of OST’s which affect emergency diesel generator availability. In addition, the following procedures were reviewed to verify safety system availability was properly evaluated and reported as specified in NEI 99-02.

- 1OST-36.1 Diesel Generator No. 1 Monthly Test, Rev. 30
- 1OST-36.2 Diesel Generator No. 2 Monthly Test, Rev. 32
- 2OST-36.1 Emergency Diesel Generator [2EGS*EG2-1] Monthly Test, Rev. 30
- 2OST-36.2 Emergency Diesel Generator [2EGS*EG2-2] Monthly Test, Rev. 31

b. Findings

No findings of significance were identified.

.4 Drill/Exercise Performance, ERO Drill Participation, Alert and Notification System Reliability

a. Inspection Scope

The inspectors reviewed the licensee's process for identifying the data that is utilized to determine the values for the three emergency preparedness PIs which are: 1) Drill and Exercise Performance, 2) Emergency Response Organization Participation, and 3) ANS Reliability. The inspectors reviewed data from the third quarter of 2000 through the second quarter of 2001 using the criteria of NEI 99-02. Attendance records for drill and exercise participation were reviewed. Alert and Notification System test data was reviewed in conjunction with inspection efforts associated with Section 1EP2 above.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

The inspectors identified that resolution of safety-related procedure performance errors (e.g., emergency diesel generator monthly surveillance test) was ineffective as described in Section 1R22.

4OA3 Event Follow-up

(Closed) LER 05000412/01-01: Automatic Reactor Trip Due to Loss of Condensate Pump. This event was discussed in NRC Inspection Report Nos. 50-334(412)/01-02. The inspectors verified that corrective actions were appropriate to preclude recurrence and were being implemented on a schedule that was commensurate with the safety significance of the event. No new issues were revealed by the LER. This LER was closed during an onsite review.

4OA5 Other

.1 TI 2515/145 - Circumferential Cracking of Reactor Pressure Vessel (RPV) Head Penetration Nozzles

a. Inspection Scope

The inspectors reviewed the licensee's activities to detect circumferential cracking of RPV head penetration nozzles in response to NRC Bulletin 2001-01 as required by TI 2515/145. This included interviews with analyst personnel, reviews of qualification records and procedures, and observations of selected video tape records of the reactor vessel head visual examination. The inspectors independently viewed a sample set of 23 out of the total 66 penetrations examined by the plant staff. In accordance with TI 2515/145, inspectors verified that deficiencies and discrepancies associated with the RCS structures and the examination process were identified, and that they were placed in the licensee's corrective action process.

b. Findings

No findings of significance were identified.

The specific reporting requirements of TI 2515/145 are documented in Attachment 1.

.2 Licensee Strike Contingency Plan Review

a. Inspection Scope

The International Brotherhood of Electrical Workers (IBEW) Local 29 contract with FENOC was scheduled to expire on September 30, 2001. This union represents approximately 450 employees at Beaver Valley Power Station from various departments. A strike by union personnel could affect plant safety or plant operational status by removing or redirecting resources (i.e. operators, technicians, or maintenance personnel) from key operational and support positions. The inspectors met with FENOC management personnel and IBEW Local 209 representatives to discuss the likelihood of a strike or worker lockout, and to discuss intentions regarding continued unfettered access to the facility for NRC safety inspectors. Additionally, the inspectors reviewed the Beaver Valley Safeguards Contingency Plan and the Beaver Valley Emergency Operating Plan to determine whether appropriate contingency measures were established to ensure that licensed activities would be conducted safely and public safety would be maintained in the event of a strike. The inspectors evaluated whether these plans properly addressed applicable requirements of 10 CFR 40.31, 10 CFR 50.34, 10 CFR 50.47, 10 CFR 50.54, 10 CFR 50 Appendix E, 10 CFR 55.31, 10 CFR 55.53, 10 CFR 60.160, 10 CFR 70.22, 10 CFR 73 Appendix C, and the Beaver Valley Unit 1 & 2 Technical Specifications.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

The inspectors presented the inspection results to Mr. Lew Myers, Senior Vice President FENOC, and other members of licensee management following the conclusion of the inspection on October 5, 2001. 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 September 26, 2001, Mr. John Rogge, Chief, Reactor Projects Branch 7, toured Beaver Valley Power Station and met with the resident staff and station personnel to review plant performance.

ATTACHMENT 1
TI 2515/145 - CIRCUMFERENTIAL CRACKING OF RPV HEAD PENETRATION NOZZLES, REPORTING REQUIREMENTS

a.1. The examination was performed by qualified and knowledgeable personnel. Although the visual examination performed was to determine leakage, the inspectors found that the plant staff invoked the additional requirements of VT-1 examination for personnel, equipment, and technique as described in the licensee's response to NRC Bulletin 2001-01.

a.2. The visual examination was in accordance with approved and adequate procedures.

a.3. The examination was adequate to identify, disposition, and resolve deficiencies.

a.4. The examination performed was capable of identifying the primary water stress corrosion cracking phenomenon described in the Bulletin.

b. The general condition of the Reactor Pressure Vessel (RPV) head was clean bare metal with some localized staining and grit like debris which appeared to be a mixture of corrosion products, dry boron flakes and dirt. The step insulation configuration does not provide easy access for examination; however, the visual obstructions were overcome by the use of a video probe delivered through guide tubes and robotic crawlers. The video taped inspection shows boron deposits at the local RPV head areas around nozzles #59 and #65. These boron deposits were evaluated and determined to be from previous conoseal leaks that are above the RPV nozzle interface. There was observed corrosion of the RPV head forging less than 1/8 inch deep for approximately ½ inch radially around the base of nozzle #65.

c. Small boron deposits, as described in NRC Bulletin 2001-01, could be identified and characterized by the visual examination technique used. None were found during this visual inspection.

d. No material deficiencies associated with concerns in NRC Bulletin 2001-01 were found.

e. The ALARA radiation exposure controls for the visual examination process were effective with a completed job dose of 2.86 person-rem, which was about 80 percent of the project estimate. Past and future conoseal leakage was the only identified item observed during the inspection that does challenge and could potentially impede effective examinations in the future. However, it was concluded that the conoseal leakage to date did not mask leakage from nozzle penetrations.

Additionally, TI 2515/145, Section 04.04 c, requires that inspectors report lower-level issues concerning data collection and analysis, and issues deemed to be significant to the phenomenon described in Bulletin 2001-01. The lower-level issues identified by the inspectors are reported below.

1. The inspectors questioned the complete video camera coverage of RPV head CRDM penetration number #53 and noted that normal three way communication was not apparent from the video record for that penetration. The licensee wrote

CR 01-6207 to investigate the complete examination coverage at CRDM #53. Although the audio record did not always match what was being viewed and tape-recorded, the inspectors verified the licensee's CR disposition that there was adequate video/inspection coverage to confirm the absence of leakage around CRDM 53 penetration. This issue was not a violation of NRC requirements.

2. The inspectors observed that there was no CR issued on the localized corrosion identified by the plant staff on the RPV head forging at CRDM penetration #65. The licensee wrote CR 01-6247 on September 20th, to document the assessment of the corrosion damage at the base of CRDM penetration 65. This issue was not a violation of NRC requirements.

3. The inspectors observed that the plant staff did not have cause evaluations or disposition documents regarding the previous conoseal leaks that occurred several operating cycles earlier on the RPV head. This was not risk significant since the leakage is historical and the remaining boron deposits under the head insulation from these specific leaks were not an impediment to this NRC Bulletin 2001-01 examination. The licensee acknowledged the inspectors' observation that addressing conoseal leaks (including cause) is of increased importance because this leakage does present NRC Bulletin 2001-01 visual examination challenges and could be an impediment to effective nozzle penetration examinations in the future.

ATTACHMENT 2
SUPPLEMENTAL INFORMATION

a. Key Points of Contact

R. Bisbee	Supervisor, Corrective Actions
T. Cosgrove	Manager, Licensing
C. Hawley	Manager, Design Engineering
W. Kline	Manager, Life Cycle
M. Mitchell	Supervisor, Nuclear Engineering
L. Myers	Senior Vice President, FENOC
G. Oakley	Manager, Planning and Scheduling
L. Pearce	Plant General Manager
M. Pearson	Director, Plant Services
R. Scheib,	Supervisor, Unit 2 Operations
B. Sepelak	Regulatory Affairs
G. Storolis	Superintendent, Nuclear Quality Assessment
B. Tuite	Manager, Outage Management
S. Vicinie	Manager, Emergency Preparedness
F. von Ahn	Director, Plant Engineering

b. Items Opened, Closed and Discussed

Opened/Closed

50-334/01-08-01	NCV	Inadequate Corrective Action for Misperformance of Safety Related Procedures (Section 1R22)

Opened

50-334; 50-412/01-08-02	URI	Potential Failure to Fulfill Function of RSPS 10 CFR 50.47(b)(5) Concerning the Personal Home Alerting Devices Portion of the ANS and Potential Failure to Correct a Problem Associated with a RSPS (Section 1EP2)

Closed

05000412/01-01	LER	Automatic Reactor Trip Due to Loss of Condensate Pump (Section 4OA3)

c. List of Documents Reviewed

RT-600, General Requirements for Radiographic Examination, Rev. 5
RT-604, Radiographic Exam of Piping Circ. Butt Welds governed by Section III 1992 Edition, Rev. 2
54-ISI-357-01, Procedure for the Visual Examination for Leakage of Reactor Head Penetrations
NDE -VT-510, Visual Examination for Boric Acid, Rev. 7 & 8

Inspection Plan 6010653A, Reactor Head Nozzle Penetration Remote Visual Inspection Plan for Beaver Valley Unit 1 Refuel Outage number 14
Beaver Valley Power Station, Unit 1 & 2 Response to Bulletin 2001-01, “Circumferential Cracking of RPV Head Penetration Nozzles”
NDE Certification Records for Framatome personnel, PO 7068473 and qualification records for FENOC NDE staff
CR 01-3666, Visual Exam Personnel Certification Revocation
CR 01-3054, BV-SA-0133 Areas for Improvement (ISI Self Assessment)
CR 01-5866, Lack of Planning for RV CRD Exam Effort
CR 01-2280, Boric Acid Walkdown
Sample of the Video tapes of RV head exam which included 23 of 66 head penetrations
CR 01-6207, Reactor Vessel CRD Penetration Examination Coverage Question
CR 01-6247, Corrosion Damage at the Base of CRDM Penetration #65
BVPS ECT Site- specific performance demonstration document dated September 2001
Logic Charts for ECT
BVPS U1 SG Degradation Assessment (SG-01-007) for 1R14 dated 8/27/01
BVPS U1 Steam Generator anticipated workscope for 1R14, Rev. 2
ISIE-ECP-2, BVPS SG Examination Program, Rev. 13
In-situ pressure testing ECT screening criteria for 1R14
List of SG pressure tested tubes (13 total) and the corresponding ECT determined indications
Steam Generator Eddy Current Inspection Data Summary, dated 9/20/01
Visual Examination Report, VT-01-076, dated 9/5/01 including SGs A, B, C, H/L manways
1R14 Boric Acid Walkdown Tracking Matrix, dated 9/3/01
Ultrasonic Test Report UT-01-001 for Weld DLW-LOOP3-7-S-02, dated 9/5/01
Ultrasonic Test Report UT-01-002 for Weld WFPD-23-1-F-03, dated 9/14/01
FAC measurement report WP-01-117 and mitigation documentation for 1-S1E-03-02T, Location 7, a 24X18" T connection
FAC examination list for 1R14 under Work Order 00-029631-000 and CR 01-5809
Evaluation of SG deposit samples taken during 1R13, Report LTR-CDME-00-119, dated 9/26/00
NDE History of BVPS RPV Nozzle-to-Safe End Welds, dated 10/20/00
Memo dated 5/2/01 from G. Alberti to C. Dodd transmitting BVPS U1 SG ECT information
List of 1R14 completed ISI examinations as of 9/20/01

d. List of Acronyms

1R14	Unit 1 14th Refueling Outage
AC	Alternating Current
AFW	Auxiliary Feedwater
ALARA	As Low As Is Reasonably Achievable
AMSAC	ATWS Mitigation System Actuation Circuitry
ANS	Alert and Notification System
ARP	Alarm Response Procedure
ATWS	Anticipated Transient Without Scram
BVPS	Beaver Valley Power Station
BVT	Beaver Valley Test

CA	Corrective Action
CFR	Code of Federal Regulations
CR	Condition Report
CRDM	Control Rod Drive Mechanism
DCP	Design Change Package
E-Plan	Emergency Plan
ECCS	Emergency Core Cooling System
ECT	Eddy Current Testing
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
EPRI	Electric Power Research Institute
EPZ	Emergency Preparedness Zone
ERO	Emergency Response Organization
°F	Degrees Fahrenheit
FAC	Flow Accelerated Corrosion
FEMA	Federal Emergency Management Agency
FENOC	FirstEnergy Nuclear Operating Company
FME	Foreign Material Exclusion
FW	Feedwater
HP	Health Physics
HRA	High Radiation Area
IA	Instrument Air
IBEW	International Brotherhood of Electrical Workers
ICE	Individual Cell Equalizer
IN	Information Notice
iaw	in accordance with
ISI	Inservice Inspection
KV	Kilovolt
LER	Licensee Event Report
LHSI	Low Head Safety Injection
MR	Maintenance Rule
MRSC	Maintenance Rule Steering Committee
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NPDAP	Nuclear Power Division Administrative Procedure
NRC	Nuclear Regulatory Commission
NSS	Nuclear Shift Supervisor
NUREG	NRC Technical Report Designation
OCB	Oil Circuit Breaker
OM	Operating Manual
OST	Operating Surveillance Test
PHAD	Personal Home Alerting Device
PI	Performance Indicator
PMT	Post Maintenance Test
QA	Quality Assurance
RCA	Radiologically Controlled Area

RCS	Reactor Coolant System
RPV	Reactor Pressure Vessel
RSPS	Risk Significant Planning Standard
RV	Reactor Vessel
RWP	Radiological Work Permit
SDP	Significance Determination Process
SSCs	Structures, Systems, and Components
Tavg	Average RCS Temperature
TER	Technical Evaluation Report
TI	Temporary Instruction
Tref	Reference RCS Temperature
TS	Technical Specification
TTB	Time to Boiling
UPS	Uninterruptible Power Supply
URI	Unresolved Item
V	Volt
WO	Work Order