U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-334/86-11

Docket No. 50-334

Licensee: Duquesne Light Company
One Oxford Center
301 Grant Street
Pittsburgh, PA 15279

Facility Name: Beaver Valley Power Station, Unit 1

Location: Shippingport, Pennsylvania

Dates: May 22 - June 25, 1986

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Date

Inspection Summary: Inspection No. 50-334/86-11 on May 22 to June 25, 1986.

Areas Inspected: Routine inspections by the resident inspectors (175 hours) of licensee actions on previous inspection findings, outage activities, housekeeping, fire protection, radiological controls, physical security, outage maintenance and modification activities, Backup Indicating Panel Testing, Radiological Environmental Monitoring Program, Inservice Testing, and followup on IE Bulletins and LERs.

Results: One violation was identified (failure to functionally test BIP, detail 7). Significant items reviewed included fuel rod cladding damage (detail 4.a.1), steam generator tube thinning (detail 4.a.2), a licensee identified security violation (detail 4.b) and reactor trip breaker modifications (detail 5.c).

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DETAILS

1. Persons Contacted

During the report period, interviews and discussions were conducted with members of licensee management and staff as necessary to support inspection activities.

2. Plant Status

The reactor remained in a refueling outage and was completely defueled by June 10, 1986. Major outage activities underway include 10 Year Inservice Inspection of the reactor vessel, eddy-current inspection of all steam generators due to the identification of cold leg thinning in the B generator, Type B and C leak rate testing of containment penetrations, and fuel examination and replacement of three fuel rods in one assembly due to baffle jetting. Restart is tentatively scheduled for the second week in August, 1986.

3. Followup on Outstanding Items

The NRC Outstanding Items (OI) List was reviewed with cognizant licensee personnel. Items selected by the inspector were subsequently reviewed through discussions with licensee personnel, documentation reviews and field inspection to determine whether licensee actions specified in the OIs had been satisfactorily completed. The overall status of previously identified inspection findings was reviewed, and planned and completed licensee actions were discussed for those items reported below:

(Closed) Unresolved Item (83-07-09): Licensee resolution of the load effects on the steam generator nozzles. This item was initiated to determine whether PSA mechanical snubbers could be applied at locations where occasional dynamic loading is expected to remain unidirectional for a critical period of time, such as during a high energy line break. Details concerning the resolution of this item are contained in NRC Inspection Report 50-334/84-25. Nozzle loading and acceptance criteria were reviewed and approved by both Westinghouse and the licensee. No further action is planned and this item is closed.

(Closed) Unresolved Item (84-04-03): Development of administrative controls to ensure that appropriate prerequisites and initial conditions are met and documented prior to removing portions of miscellaneous plant safety systems from service. Station Administrative Procedure 3D, The Maintenance Work Request (MWR) and OM Chapter 48, Conduct of Operations, contain guidance on the use and procedures for MWRs and equipment clearance permits (ECP). It is the responsibility of the supervisor originating the ECP to determine the scope of the work, the work start date and time and an estimation of work duration. Completion of this requires the originator to thoroughly review the proposed ECP and assure the correct initial conditions and prerequisites are present for equipment release. Also, before work is permitted to begin, the work party must receive approval of the Shift Supervisor, documented on the MWR in the "Authorization to do work" block. The inspector reviewed several ECPs and MWRs for various control room annunciators and indicators to assure the procedures were being adhered to. The inspector had no further concerns.

(Closed) IFI (85-17-04): Licensee evaluation of Estimated Critical Position (ECP) calculation method to identify if a systematic error exists. The licensee reviewed various startup parameters throughout Cycle 5 and determined that, on the average, criticality was achieved about 300 pcm before that predicted by the ECP. Technical Specification 4.1.1.1.2 allows an error in the ECP of 1000 pcm. Further investigation revealed that the power defect factor contributed the largest error to the calculation. This is because Westinghouse used a two dimensional core analysis for the prediction of power defect. This method is acceptable but a three dimensional core analysis is more accurate. For Cycle 6 a three dimensional core analysis will be used to predict power defect. The licensee will incorporate these new values into the ECP calculations and will monitor the results in their trending program. The inspector had no further concerns.

(Closed) Unresolved Item (85-25-01): Licensee to make changes to OM 1.56C.4, Alternate Safe Shutdown Procedure, to assign the primary responsibility for hooking up source range monitor to the STA instead of the NSS. The inspector verified that the necessary changes were ORC and OSC reviewed and approved and incorporated into the procedure on December 30, 1985. The inspector had no further concerns.

(Closed) Unresolved Item (85-25-02): Licensee to make improvements to "Appendix R" key rings to minimize time for proper key selection when performing Alternate Safe Shutdown Procedure. The inspector observed that the keys on the key rings which are not already easily distinguishable by virtue of their shape or size have been marked with colored gaskets around the wide end or colored dots. The color coding corresponds with the information provided on laminated cards; which lock each key fits and the key color code and number where applicable. Through discussions with licensee personnel, the inspector verified their familiarity with the color coding and the cards. The inspector had no further concerns.

(Open) Violation (86-06-01): Failure to demonstrate individual smoke detector operability in that a complete functional test was not performed to verify control room alarm function for each detector. The inspector reviewed the licensee's corrective actions as described in the DLC letter dated June 4, 1986. The corrective actions committed to are to revise test procedure, OST 1.33.16, Smoke Detector Instrumentation Test, to clarify the testing requirements, and to emphasize to the vendor the importance of procedure adherence while performing work at the site. The inspector verified that the OST has been revised, and reviewed the Honeywell, Inc. letter dated May 29, 1986. This letter describes their actions to prevent recurrence which include requiring all technicians working at the plant to review a checklist highlighting procedural requirements of DLC before performing the semi-annual smoke detector OST. The inspector had no further concerns related to these corrective actions; however, the inspector questioned if these actions will also apply to vendors other than Honeywell who perform surveillance tests for DLC which satisfy technical specification requirements. The licensee is evaluating the tests performed by vendors and this item will remain open pending this review and if necessary, implementation of actions taken to ensure that procedures are adhered to by the other vendors.

(Closed) Unresolved Item (84-25-04): This item was initiated to follow licensee corrective actions resulting from a craft worker's violation of radiation control postings in the Turbine Building while radiography was in progress in the area. The inspector witnessed radiography in progress in the Turbine Building on June 1, 1986, and noted that all access points to the area were positively controlled by either security or radcon personnel. The inspector also reviewed the General Employee Refresher Training (GERT) student handout to verify that the instruction does emphasize the significance of radiological control barriers and postings. The inspector also noted that a question describing conditions similar to this incident has been added to the GERT exam.

(Closed) Inspector Follow Item (85-19-01): Evaluation of EPP/IP 3.2, Personnel Accountability, because there was confusion regarding accountability of personnel in the assembly areas during the EPP drill in September, 1985. EPP/IP 3.2 was revised in February, 1986, to further clarify the instruction for accounting of personnel and visitors onsite. Review of the GERT student handout indicated that personnel assembly areas and responsibility to be accounted for are adequately addressed. The inspector had no further concerns.

(Closed) Deviation (86-06-03): EDG fuel oil tank construction, installation and inspection not seismic. See detail 5.b of this report.

(Closed) Unresolved Item (81-20-02): Review DLC actions for high background levels on liquid waste effluent rad monitors. Technical Specification 3.3.3.9, Radioactive Liquid Effluent Monitoring Instrumentation, requires effluent monitor RM-LW-104 to be operable with its alarm and trip setpoints set to ensure that the limits of radioactive material released are within the concentration specified in 10 CFR Part 20, Appendix B. When this monitor is inoperable, effluent releases through this path are allowed to be conducted per Action Statement 23, provided that at least two independent samples are analyzed and two technically qualified members of the facility's staff independently verify the release rate calculations and discharge valving. This unresolved item was originally opened to track the licensee's long term corrective action to either modify or replace the detector with a quick change disposable detector well because the current design allowed a crud buildup resulting in high background levels and necessitating routine detector decontamination and use of Action Statement 23.

The inspector reviewed Engineering Memo 72304 dated April 30, 1986, addressing the licensee's position on this item. The station performed a historic review of the liquid waste effluent discharges and determined that in the 1981 time period, BVPS-1 was discharging approximately 2,000 gallon batches of water 2 to 3 times daily. With the above discharge rates, high-high alarms on RM-LW-104 occurred two to three times daily. This resulted from a quick crud buildup that could be corrected only by detector removal and decontamination (usually in the form of electro-polishing). The station had originally considered installing a new model rad monitor as the old model was requiring decontamination approximately once every five weeks. However, from the period of 1984 to April, 1986, decontamination was required on only five occasions as previous station efforts to reduce the total liquid waste effluent volume has been successful. The licensee performed a cost benefit analysis based on this information and determined that the current station practice of discharging large volume, low concentration batches over an extended period of time, promoted sufficient flushing of the monitor sample chamber to result in low crud buildups. The inspector verified that current rad waste discharge authorizations had not had a problem with exceeding the high alarm setpoints. This item is closed.

(Closed) Violation (86-06-02): Monthly remote shutdown monitoring instrumentation channel check failure to qualitatively assess TRB-RH-606 as inoperable when indicated readings were off-scale low at less than expected ambient temperatures. Licensee evaluation of the circumstances surrounding this violation resulted in the identification of two items which materially contributed to this problem. The acceptance criteria contained in the test procedures were inadequate and an inconsistency was present in the technical specifications (TS). The test acceptance criteria were inadequate in that the requirements only compared the shutdown panel instrument response to the control room temperature recorder with no qualitative assessment of the expected response. The inconsistency was identified with TS 3.3.3.5 as compared to TS 3.3.1.1. and TS 3.4.1.3. The first requires RHR Heat Exchanger Outlet Temperature operability and channel checks in Mode 1 while the second two TSs do not require system level operability in Mode 1. The licensee has determined that the requirements of TS 3.3.3.5 are non-conservative and unnecessarily restrictive as they could force the plant into a shutdown condition which would require the use of this instrumentation. A TS amendment request will be submitted by October 1, 1986.

The licensee has completed the following corrective actions taken to prevent any further similar occurrences. All applicable surveillance test procedures were revised to require more critical examination of shutdown panel instrumentation. All control room and shutdown panel instruments that are part of the surveillance program were checked to ensure that calibrations were current; none were found out of calibration. All open MWRs were reviewed to determine if any other instrumentation required by TS was inoperable; none were found. This incident was presented to Operations personnel during Requalification Training Module 6 by the Site Operations Director. Appendix C of the Instrumentation and Control Department Manual has been placed in the shift supervisor's office for reference in determining the applicable TS requirements for this type of instrumentation. The inspector verified that the above actions have been carried out and that operations personnel are aware of the TS requirements concerning instrumentation operability.

(Closed) IFI (85-07-01): Comparison of licensee analytical results to BNL results for reactor coolant and steam generator samples. During inspection 334/85-07, the reactor coolant and steam generators were sampled for analysis. Duplicate samples were sent to the Brookhaven National Laboratory (BNL) for independent verification of analysis. A statistical evaluation was made on the boron and ammonia analyses. For the other analyses, a statistical comparison was not made because the uncertainties were not available.

SPLIT SAMPLE COMPARISON

Sample Source	Chemical Parameter	BV#1 Value	BNL Value	Comparison
		Results in parts per million (ppm)		
Reactor Coolant	Boron	963 ± 1	969±33	Agreement
	Chloride	<0.010	<0.010	Agreement
	Fluoride	<0.025	<0.0054	Agreement
		Results in parts per million (ppm)		
Steam Generator	Silica	0.024	<4	Agreement
	Chloride	<0.010	<0.010	Agreement
	Ammonia	623±8	677±7.8	Disagreement
		Results in parts per billion (ppb)		
Steam Generator	Hydrazine	<5	3.9	Agreement
	Iron	<0.5	<50	Agreement
	Copper	<0.5	<50	Agreement

The ammonia analysis was the only one that was in disagreement. This was probably due to the sampling and evaporation of the BNL portion. The analytical comparisons for the other analyses were acceptable. This item is closed.

(Closed) Inspector Follow Item (84-BU-03): Provide additional information on inflatable seals and possible failure modes. This item was discussed at length in NRC Inspection Report 334/86-07, detail 5. The inspectors have no further concerns.

4. Plant Operations

a. Refueling Outage Activities

Inspection tours of all accessible plant areas were conducted during both day and night shifts to verify Technical Specification (TS) compliance, housekeeping and cleanliness, fire protection, radiation control, physical security and plant protection, and operational and maintenance administrative controls.

The inspectors regularly verified compliance with NRC requirements and TS during operational mode changes, core alterations, and selected outage work activities. Included in these reviews were plant radiation monitors, nuclear instrumentation systems, onsite and offsite emergency power sources, refueling water chemistry, control of boration and dilution flow paths, containment integrity and ventilation requirements, decay heat removal, and availability of necessary engineered safety features systems. Also, various operation logs and records, including completed surveillance tests, equipment clearance permits in progress, status board maintenance and temporary operating procedures were reviewed on a sampling basis.

During the course of the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration and plant conditions. The inspector verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. Except where noted below, the inspector comments or questions resulting from these daily reviews were acceptably resolved by licensee personnel.

1. Fuel Assembly Baffle Jetting Damage

Visual observation identified two potentially damaged fuel assemblies during the reactor core offload on June 5, 1986. Each assembly (core positions D-13 and M-13) was located at a baffle corner and had completed its third and final fuel cycle. The inspector reviewed the video tape made during the underwater camera examination. The suspected rod bowing on M-13 was not present. However, D-13 had several areas where the cladding had been breached. These areas were located about one inch below the bottom of the grid strap and extended up to several inches above the top. Grid spring and mixing vane damage had occurred. Several pieces of what appeared to be fuel pellets were observed on the top of at least one grid strap. Damage was limited to three front row and possibly three second row rods in the 17x17 array. No other corner assemblies showed evidence of baffle jetting damage.

The inspector discussed planned corrective actions with senior licensee management representatives. The station has decided to reconstitute the assembly scheduled to be placed in D-13 with solid stainless steel tubes at the damaged rod locations. Westinghouse (the NSSS and fuel vendor) is to provide a 10 CFR 50.59 safety evaluation for the reload modification. The inspector discussed this plan of action with NRR through the License Project Manager and found it acceptable.

Primary system chemistry sample records were reviewed for the last cycle. Technical Specification 3.4.8 limits the specific activity of the primary coolant to less than or equal to (1) 1.0 micro Curies/gram dose equivalent I-131, and (2) 100/E Bar micro Curies/gram. The maximum I-131 (unmodified peak) concentration was 3 E-2 micro Ci/gm. The January and May samples for E Bar were also well within limits, indicating that the fuel cladding problem was limited to only several rods.

Weekly iodine samples, particularly for the I-131 isotope, indicated that the fuel failure probably occurred in August, 1985. Activity increased from 9.8 E-4 micro Ci/gm to 1.7 E-3 micro Ci/g in a one week period, and steadily tracked up to about 6 E-3 micro Ci/gm before the end of cycle shutdown. A Westinghouse analysis for DLC predicted that 4 (plus or minus 2) fuel rods were defective. This is consistent with the information that DLC management verbally gave the inspector earlier in the year.

2. Steam Generator Tube Degradation

Technical Specification 3.4.5, Steam Generators, requires the routine inspection of a tube sample size by eddy-current examination per ASME Section XI. The licensee conducted a 100% multi-frequency eddy-current inspection of the B steam generator to meet the requirements of TS 3.4.5 and to provide future baseline data for trending purposes. The results of this inspection identified approximately 15 tubes that had greater than the 40% thru wall indications and require plugging. This placed the steam generator into the C-3 category of TS Table 4.4-2 which requires inspection of the other two generators. Review of records and discussions with licensee personnel indicated that the suspected failure mechanism is cold leg thinning; a process whereby a combination of chemical attack and mechanical wear takes place at the tube support plate. Specifically, this phenomena was observed at the outer peripheral (the first five rows) of the tube support plates No. 2 and 3. Consequently, the licensee has prepared to perform an additional eddy-current inspection of the remaining two steam generators with a sample biased towards those areas that have experienced the indicated potential problems. NRC specialist report 334/86-09 reviewed the test methodology and data analysis.

After opening up the secondary side of the steam generators, the licensee retrieved several loose parts that were previously part of the flow control valve anti-rotation devices. However, not all of the missing loose parts from these devices have been accounted for and some are still expected to be somewhere in either the feedwater ring or feedwater header. The inspectors will continue to followup licensee action which is being tracked as Unresolved Item (85-24-01).

3. RCS Loop Stop Valve Work

While attempting to isolate the three reactor coolant system loops, the A loop cold leg isolation valve (MOV-RC-591) failed to close the last four inches. Subsequent investigation by the licensee identified a loose valve disc guide pin. This problem has been identified at other plants that utilize the Westinghouse RCS loop isolation maintenance valve. Corrective actions consist of replacing the guide pins with that of a different design (dog-eared) to provide for greater surface contact area. At this time, the licensee opted only to do the modification on MOV-RC-591 and defer any preventive action on the remaining five loop isolation valves until a future date.

After removing the 28 valve body studs, the licensee performed nondestructive examination per their IEB 82-02 commitments. The results of this examination will be reviewed by a Region I Specialist in a future inspection. After reassembly, the valve was successfully tested using the MOVAT system on June 15, 1986.

4. Overflow of Refueling Cavity

On June 20, 1986, there was an accidental overflow of about 473 gallons of refueling cavity water into the containment sump. In response to a refueling cavity water level rise to within a few inches of the operating deck, the licensee was draining several inches of water from the spent fuel pool to the RWST in preparation for cross connecting the refueling cavity and spent fuel pool to lower cavity level. Operators performed the correct system lineup for the evolution and checked the status of other system valves by the valve status prints in the Control Room. When drainage to the RWST was initiated, rad techs in containment observed water cascading from the operating deck to the area where the vessel head is stored; drainage was immediately stopped. Investigation revealed that valve PC-37 from the fuel pool filters to the refueling cavity was open instead of closed as indicated on the control room print. The licensee corrected the valve lineup and the control room print and continued the evolution. Currently, the licensee is evaluating this incident to determine the cause and any necessary corrective measures to be taken to preclude recurrence of the plant configuration control problem.

b. Plant Security/Physical Protection

Implementation of the Physical Security Plan was observed in the areas listed in paragraph 4a above with regard to the following:

-- Protected area barriers were not degraded;

-- Isolation zones were clear;

-- Persons and packages were checked prior to allowing entry into the Protected Area;

-- Vehicles were properly searched and vehicle access to the Protected Area was in accordance with approved procedures;

-- Security access controls to Vital Areas were being maintained and that persons in Vital Areas were properly authorized.

-- Security posts were adequately staffed and equipped, security personnel were alert and knowledgeable regarding position requirements, and that written procedures were available; and

-- Adequate lighting was maintained.

The inspector was informed by the licensee that a security violation occurred at 12:30 p.m., on June 23, 1986. Apparently, a vital area roof hatch was removed by plant maintenance personnel using a crane without the presence of security personnel as a compensatory measure. The opening was needed to replace the 1B low head safety injection pump motor. According to the licensee, the foreman notified security of the intended work; waited for a period of time, and then pulled the hatch and lowered the pump motor before the guards reported to the work site. This was contrary to plant security procedures of which the foreman was aware. No one entered or exited through the roof hatch. The last time a similar event occurred, a violation was issued (82-06-04). Programmatic changes following that event were judged adequate. Since the current event was identified and reported by the licensee, similar violations had not occurred in the past two years and appropriate disciplinary action was taken to ensure that personnel understand the importance of maintaining the integrity of the vital areas, no violation will be issued.

c. Radiation Controls

Radiation controls, including posting of radiation areas, the conditions of step-off pads, disposal of protective clothing, completion of Radiation Work Permits, compliance with the conditions of the Radiation Work Permits, personnel monitoring devices being worn, cleanliness of work areas, radiation control job coverage, area monitor operability (portable and permanent), area monitor calibration and personnel frisking procedures were observed on a sampling basis.

No deficiencies were observed.

d. Plant Housekeeping and Fire Protection

Plant housekeeping conditions including general cleanliness conditions and control of material to prevent fire hazards were observed in areas listed in paragraph 4a. Maintenance of fire barriers, fire barrier penetrations, and verification of posted fire watches in these areas were also observed.

No deficiencies were observed.

5. Outage Maintenance and Modification Activities

a. Station Batteries

The inspector periodically witnessed the installation of new station batteries (1-3 and 1-4) per DCP 673. This will complete the changeout of all safety-related batteries. During one walkdown of the 1-3 battery, it was noted that not all of the threads were engaged on the post strap connectors. Review of the installation package and discussions with engineering personnel indicated that this item had been dispositioned as acceptable because lateral loads would not be experienced during a seismic event and the installed configuration represented the one tested and qualified by the vendor.

The seismic support racks installed for the C&D company batteries had no gap specification for the corner bars to allow for thermal expansion of the cells. This problem resulted in the cell crazing on the original batteries. Discussions with the QC inspectors indicated that none had been specified by station engineering.

Subsequent contact with NED indicated that none was needed per the manufacturer because the lead-calcium batteries have a minimum thermal expansion coefficient. The inspector had no further questions.

b. Emergency Diesel Generators

The 18 month preventive maintenance activities were periodically reviewed to ensure that they were conducted per approved procedures. During replacement of the lube oil, maintenance personnel noted that a new drum of Mobil oil appeared contaminated. The oil grade was as specified by the licensee for use in the EDGs. The lube oil system was subsequently drained and recleaned to specification.

Deviation (86-06-03) identified deficient welds on the EDG day fuel oil tank supports. By letter dated June 4, 1986, DLC committed to correct this condition to assure that the as-built supports of the vendor supplied tank were enveloped by the seismic calculations. The inspector witnessed the installation of the Number 2 tank supports per DCP 739, and found the licensee's actions acceptable. At the conclusion of this inspection period, work was underway on the Number 1 tank. This item is closed.

c. Reactor Trip Breakers

Routine preventive maintenance activities and the shunt trip modifications of DCP 622 were witnessed for RTB B (DB-50). During discussions with the vendor's representative directing the work, the inspector was informed that a new undervoltage coil just installed was running abnormally hot. Should this coil fail while the reactor is operating, the result would be either a spurious reactor trip or the loss of the redundant breaker trip function. Discussions with cognizant DLC electrical maintenance engineers indicated that this condition would be investigated by Westinghouse as both breakers had to be sent offsite for refurbishment of several items that were found out of tolerance (trip bar slightly bent and G gap for open contact space was less than specified). Resolution of the defective undervoltage coil and possible reportability will be followed as Unresolved Item (86-11-01).

d. Main Steam Isolation Valves

All three MSIVs (manufactured by Schutte & Koerting) were disassembled and inspected by Crane Valve Service using an approved plant maintenance procedure. The inspector noted that QC was present for much of the field work. Both the A and C valves had sustained some seating damage caused by flapper closure during the last safety injection at power. Discussions with DLC personnel indicated that portions of the seat would have to be built up (welding) and then relapped to tolerance to assure a leak tight fit. For the C valve, the disc and rocker shaft required replacement.

All MSIV actuators were disassembled and inspected. Because some of the stems were pulling out of the piston (normally held in place by peening the end of the stem over the piston), a modification was made to three of the six actuators. It consisted of remachining the stem and adding a washer and capscrew, drilling a locking pin and then peening. EM 61843, dated June 17, 1986, approved this change. The inspector identified no concerns.

e. Refueling Cavity Modifications

The inspector periodically observed the installation of the cofferdam and modified reactor cavity seal, which were installed in response to IE Bulletin 84-03, and evaluated in Inspection Report 86-07. After initial difficulties in installing the new reactor cavity seal were overcome, leakage into the cavity instrument pit was minimal (less than 1 gpm) due to the pressurized seal rings. No concerns were identified.

6. Surveillance Testing

To ascertain that surveillance of safety-related systems or components is being conducted in accordance with license requirements, the inspector observed portions of selected tests to verify that:

a. The surveillance test procedure conforms to technical specification requirements.

b. Required administrative approvals and tagouts are obtained before initiating the test.

c. Testing is being accomplished by qualified personnel in accordance with an approved test procedure.

d. Required test instrumentation is calibrated.

e. LCOs are met.

f. The test data are accurate and complete. Selected test result data was independently reviewed to verify accuracy.

g. The test provides for independent verification of system restoration.

h. Test results meet technical specification requirements and test discrepancies are rectified.

i. The surveillance test was completed at the required frequency.

j. Portions of the following test were observed:

-- OST 1.45.9, BIP Instrumentation and Source Range Indication Test, May 22, 1986.

-- OST 1.45.10, BIP Valve Control Switch Test, May 22, 1986.

-- BVT 1.39.2, No. 2 Station Battery Charger Load Test, May 22, 1986.

-- BVT 1.39.7, No. 2 Station Battery Capacity Test, May 23, 1986.

No concerns were identified.

7. Backup Indicating Panel Testing

a. Regulatory Requirements

10 CFR 50, Appendix R, III.L outlines the specific requirements for the provision of Alternate and Dedicated Shutdown Capabilities. Capabilities provided shall enable the licensee to achieve and maintain subcriticality, maintain reactor coolant system (RCS) inventory, achieve and maintain hot standby conditions, achieve cold shutdown conditions within 72 hours and maintain cold shutdown conditions thereafter. Section III.L.2.d of Appendix R requires that process monitoring functions are capable of providing direct reading of the process variables necessary to achieve the aforementioned plant conditions.

Scheduling requirements for the necessary Appendix R modifications are described in 10 CFR 50.48(c). 10 CFR 50.48(c)(4) pertains to the dedicated shutdown panel and requires that all features which required prior NRC approval be implemented within 30 months after the NRC approval was granted.

NRC issued the Beaver Valley Unit 1 Safety Evaluation Report (SER) for 10 CFR 50, Appendix R items III.G and III.L on January 5, 1983. The SER references the licensee's intention to provide alternate process monitoring capabilities through installation of a backup indicating panel (BIP). Exemptions for selected parts of Appendix R were granted to the licensee by NRC in a letter dated March 14, 1983. The exemption granted concerned fire protection provisions for various fire zones, charging pump cubicle ventilation modifications, portable fan usage, and an extension of the 72 hours required to achieve cold shutdown conditions to 127 hours. The installation and uses of the BIP are mentioned several times in the body of the exemption.

In a letter to the NRC dated January 14, 1985, the licensee submitted additional exemption requests to Appendix R. This letter also contains reference to the installation of the BIP and indicated that its installation will be complete by July 5, 1985; 30 months after the issuance of the SER.

b. Function and Purpose of BIP

The BIP and associated equipment were installed during the Fourth Refueling Outage (Winter 1984) under Design Change Package (DCP) 563. It was designed to provide the necessary controls and indication, in conjunction with manual operation of equipment and the use of local gages and instruments, to safely achieve and maintain cold shutdown from outside the control room if a fire should require that the control room and emergency shutdown panel area be evacuated. The BIP is located in the East Cable Vault and provides the capabilities to monitor the necessary process variables with the exception of steam pressure which is read from a local indicator in the Main Steam Valve Room.

The licensee implemented OM 1.56C, Alternate Safe Shutdown From Outside the Control Room, on July 5, 1985, which demonstrates the capability to achieve safe shutdown given a fire in any one fire area of the plant without the use of letdown, component cooling system, residual heat removal system and the Emergency Shutdown Panel. The procedure details a method of achieving stable hot standby conditions and conducting a cool down using minimal essential equipment. The Alternate Safe Shutdown Procedure was included in the fire protection inspection conducted in November, 1985, and documented in NRC Inspection Report 334/85-25. During the course of the inspection, the inspectors witnessed a walk through of OM 1.56C. However, since at that time the plant was running at full power, the licensee was unable to place the BIP into service as this would remove indications from the control room.

c. <u>BIP Surveillance Testing</u>

On May 22, 1986, the inspector observed the first performance of OST 1.45.9, BIP Instrumentation and Source Range Indication Test, which will functionally test the BIP (during Mode 5 conditions) each refueling outage. It requires that each channel of BIP and Source Range Instrumentation agree with its counterpart indication in the control room to within one graduation. The inspector identified one concern and observed three anomalies during the performance of the procedure which are discussed below.

(1) The inspector observed that the SRM and all of the parameter indicators on the BIP did not have calibration stickers attached. This sticker is a record of the date that the instrument was last calibrated and the date this calibration expires. Through review of DCP 563, it was identified that the DCP did not specify a required calibration frequency for this instrumentation. The licensee informed the inspector that calibration frequency for the SRM had been discussed but no final determination has been made. Calibration frequency for the BIP instrumentation had not previously been discussed. Currently, the licensee is evaluating this issue.

(2) Difficulty arose when operators attempted to transfer indication from the control room to the BIP through the key locking transfer switches. Each transfer switch has the same core and therefore, utilizes the same key. The keys for the OM 1.56C procedure are kept in the shift supervisor's office on rings known as the Appendix R rings. There are four rings; one for each participant in the station shutdown, each containing all of the keys which might be necessary during the shutdown process. Apparently, after the November 1985 Appendix R inspection, a human factors concern was raised dealing with operator ease in identifying important function transfer switch keys on the ring. When making necessary changes to the rings to address this concern, the licensee did not use the master keys provided with the lock switches, but had four new ones made. The new keys did not fit the locks and therefore, none of the Ap-

pendix R key rings had the capability of transferring control to the BIP. The licensee promptly located the original keys (in security) which came with the lock switches and temporarily attached the correct keys to the Appendix R rings. The licensee intends to remove the old keys and permanently attach the new ones.

(3) During the safe shutdown in accordance with OM 1.56C, the Shift Technical Advisor (STA) has the responsibility of setting up the Source Range Monitor (SRM) and performing a calibration check on it.

Initially, OST 1.45.9 did not include this action. The inspector questioned the omission of the calibration check and the licensee responded by inserting the appropriate steps into the OST. Operations personnel performed the calibration check with satisfactory results; however, when SRM indication was transferred from the control room to the BIP there was no indication. The Control Room SRM N32 indicated 225 counts per second before the transfer and the SRM at the BIP was indicating off scale low after the transfer. Instrument and Control technicians investigated the troubles with the SRM the following day and found nothing wrong. It was determined that due to poor cable labeling and operator infamiliarity with installing the SRM, that the cables connecting the SRM to the preamp had been incorrectly connected. It is expected that an operator would experience difficulties with setting up the SRM and performing the calibration check since this is the duty of the STA during the safe shutdown of the plant and therefore, this task is not covered in operator training (see closing of Unresolved Item 85-25-01 in Section 3 of this report). The licensee will relabel the cables and clarify the wording in the OST to enable a trouble free set up of the SRM during future performance of the OST.

(4) Performance of OST 1.45.9 includes a channel check between instrument indication in the Control Room before transfer to the BIP and BIP instrument indication after the transfer. When this was done for the cold leg temperature indications, all three loops (TRB-PC-410, 420 and 430) were off scale low in contrast to the desired indication of 100 degrees F. The inspector questioned why the post-modification testing (PMT) did not detect this deficiency. In response, the licensee stated that the PMT did not include a complete functional test of the BIP.

Upon further investigation, the licensee determined that three independent and unrelated errors contributed to this item. First, wiring diagrams for the RTD were in accordance with the vendor's recommended wiring configuration instead of the as-built plant configuration. Second, the post installation test procedure provided test details but selected incorrect input terminals for the RTD simulation portion of the test. And third, the portion of the wiring from the containment penetration to the transfer switch panel which was unable to be tested due to construction constraints was inadvertently left off of the DCP open item list and therefore, not tested.

It is of importance to note that in OM 1.56C.4, Section B, Shift Supervisor Procedure, the primary objective of the shift supervisor (NSS) once he has activated the BIP is to monitor the BIP for establishment of stable hot standby conditions as evidenced by the presence of natural circulation in the RCS. The procedure contains six criteria for the NSS to look for to verify natural circulation exists. Two of these six criteria require an indication of cold leg temperature, Delta T and T-average.

d. PMT Requirements for BIP

The Nuclear Engineering Management Procedure Manual Section 2.8, Handling of Design Change Packages, discusses the engineering responsibilities, interfaces and controls in implementation of DCPs. It states that after the initial design concept has been approved, it is the responsibility of the Primary and Secondary Sponsoring Engineers to develop the required installation and testing specifications for the DCP.

The inspector reviewed the PMT results for the BIP which was installed under DCP 563. The PMT did not include a complete functional test of the BIP which would involve energization of the panel and transfer of indications from the control room to the BIP. A test of this nature would have identified the inaccuracies of the cold leg temperature indication wiring. Failure to perform adequate post modification testing to demonstrate the operability of the BIP is a Violation of 10 CFR 50, Appendix B, Section XI and FSAR Appendix A Section A.2.2.11, Test Control (86-11-02). The wiring errors on the RTD connections to the BIP are not being cited as a separate violation in that testing deficiencies appear to have been the more significant problem. If testing had been properly performed, it would have identified the wiring errors.

The inspectors met with the licensee to extensively review the circumstances involved in this item. The licensee promptly responded to all concerns and performed a thorough investigation which identified the three independent and random errors. As previously mentioned, the necessary wiring changes have been made, the correct keys have been temporarily attached to the key rings and the SRM calibration is being added to the OST procedure. The inspectors had no further concerns at this time.

8. Inoffice Review of Licensee Event Reports (LERs)

The inspector reviewed LERs submitted to the NRC:RI office to verify that the details of the event were clearly reported, including the accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following LERs were reviewed:

LER: 86-02: Degradation of safety valve operability and reactor protection system actuation.

LER: 86-04: Inadequate fire protection system surveillance test.

The circumstances involved in LER: 86-02 were previously discussed in NRC Inspection Report 334/86-07, details 7.j(1) and 4.b(1) respectively. The inspector noted that both events are unrelated and do not fall under the guidance provided in NUREG 1022 (and supplements) for inclusion as a single LER. These comments were acknowledged by the Director of Site Operations.

LER: 86-04 identified an inadequacy in the fire protection system surveillance testing. Technical Specification 4.7.14.3 requires that the low pressure CO2 system be demonstrated operable once per 18 months by verifying that (1) system valves and dampers actuate manually and automatically upon receipt of a simulated actuation signal and (2) there is flow from each nozzle during a "Puff Test". These surveillance tests are contained in OST 1.33.10, CO2 Fire Protection System Test. On May 29, 1986, the inspector was informed by the licensee that a quality review of the test methodology vs. TS acceptance criteria identified a deficiency in that not all of the nozzles were routinely checked to verify flow during the puff test. Specifically, checks of the nozzles located in the cable mezzanine and two cable vault rooms had been omitted after the initial OST was erroneously revised. All other nozzles are located in open areas and are required to be visually observed by the operators during performance of the OST.

The inspector walked down the fire areas and observed the CO2 headers and flow nozzles. The test of the west cable vault system was observed on May 29, 1986. The satisfactory results indicated that these nozzles remained unplugged and that the system was always functional. Results of the revised OST were also reviewed for the east cable vault and cable mezzanine, tested on May 30 and 31, 1986. Licensee corrective action was satisfactory.

9. Radiological Environmental Monitoring Program

The inspector reviewed the licensee's Radiological Environmental Monitoring Program annual report for 1985. This report summarizes the results of the sampling and analyses of environmental media to determine the radiological impact of station operations. These environmental media include air, water, vegetation, and aquatic plants and animals. In addition, direct radiation is monitored by placement of thermoluminescent dosimeters at various locations around the station.

As a result of this review, the inspector determined that the licensee has generally complied with its Technical Specification requirements for sampling frequencies, types of measurements, analytical sensitivities, and reporting schedules. The report included summaries of the laboratory quality assurance program and of the land use survey.

The analyses of environmental samples indicated that doses to humans from radionuclides of station origin were negligible.

10. Inservice Testing

Inservice pressure testing of systems is to be performed in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section XI as stated in 10 CFR 50.55(a). These regulations allow for performance of proposed alternative testing, when authorized by NRR, if compliance with the specified requirements results in hardship or unusual difficulties; however, the alternative testing must provide an acceptable level of quality and safety.

H.A.F.A. International Incorporated (HAFA) submitted to NRR a topical report entitled "Instrument Inspection Technique (IIT) as an Alternative to the Hydrostatic Testing Requirement for ASME Class 1, 2 and 3 Systems and Components" for evaluation as an alternative method to perform pressure testing in accordance with ASME Section XI. IIT is capable of detecting and locating external system leakage, intersystem valve leakage, reducing personnel radiation exposure, detecting small leaks and eliminating overpressurization of lower pressure rated piping and components. The staff's review of IIT concluded that it is a suitable alternative to Section XI requirements for pressure testing only in situations where it is impractical to implement code requirements. IIT is not intended to circumvent the Section XI code requirements but to provide an added margin of reliability of the test results.

The licensee submitted a letter dated April 22, 1986, to NRR which requested approval for the use of IIT on selected portions of several plant systems during this refueling outage. By letter dated May 15, 1986, NRR approved this request for selected systems.

Successful IIT testing on the entire Residual Heat Removal (RHR) System was witnessed by the inspector. Justification for performance of this test was due to ALARA constraints, as the entire RHR system is inside high radiation areas of containment, and the relatively large number of valves which would need to be altered for performance of the conventional hydrostatic testing. Preliminary review of the test results by HAFA personnel indicated that the test was successful. A detailed report containing the results is being prepared for the licensee by HAFA.

IIT was also attempted on the B River Water header without success. The licensee's system lineup for the test proved to be inadequate in supplying enough flow to overcome system leakage for the test to be adequately completed. The results of this test were determined to be inconclusive and the licensee is not taking credit for this hydrostatic test. The licensee is currently developing an alternate test method and plans to perform it during the next refueling outage.

11. IEB: 85-03, MOV Common Mode Failures During Plant Transients Due to Improper Switch Settings.

This bulletin requested licensees to develop and implement a program to ensure that switch settings on certain high head safety injection and auxiliary feedwater system motor operated valves (MOV) are selected, set and maintained correctly to accommodate the maximum differential pressures expected on these valves during both normal and abnormal events within the design bases. Basic actions required of all licensees included:

a. Review and document the design basis for the operation of each valve, including the maximum expected differential pressure expected during both opening and closing for normal and abnormal events (as documented in FSAR analyses and fully-approved emergency operating procedures).

b. Use the results of the above to establish the correct switch settings and develop a program to review and revise the methods for selecting and setting all switches for each valve operation.

c. After all switch settings have been made consistent with those established in item b above, demonstrate valve operability by testing the valve at the maximum differential pressure determined by item a. Otherwise, justification that includes an alternative method shall be provided for any case where testing with maximum differential pressure cannot practically be performed. Each valve shall be stroke tested.

d. Prepare or revise procedures to ensure that correct switch settings are determined and maintained throughout the life of the plant.

e. Submit a written report that contains the results of item a and schedule for implementing a program to meet items b through d to ensure that these items are completed as soon as practical and within two years of the date of this bulletin (November 15, 1985).

f. Provide a written report within 60 days of the completion of the program summarizing its findings.

DLC responded to the above in a letter dated May 16, 1986. Table 1 reports the results of the design basis review conducted for item a. The inspector reviewed P&IDs for the CVCS and auxiliary feedwater systems and verified that the valves selected were consistent with the intent of the bulletin (valves require automatic operation as specified in applicable FSAR analysis, or are subsequently manually operated as directed by Beaver Valley's EOPs). The maximum differential pressures compared satisfactory to the design differential pressures. The 2750 delta P referenced for the centrifugal charging pumps (Pacific Co.) was verified to be that reported in the pump's Technical Manual, which can be regarded as conservative as line losses are not considered. The licensee appears to have met the requirements of item a.

DLC committed to establish the switch settings by December, 1986. The design thrust requirements and torque switch settings will be established for the identified design differential pressures by independent calculation and comparison to vendor's original calculated data. Item b therefore, remains open.

To verify the adequacy of existing valve operator torque levels, limit switch setpoints and protective overload capability, DLC plans in-plant valve testing with the Motor Operated Valve Analysis and Test System (MOVATS). During the course of this inspection period, the inspector witnessed testing of a pressurizer block valve, performed to meet INPO SOER recommended testing. At this time only 7 of 24 valves listed in Table 1 of DLC's submittal are scheduled to be tested during the current Fifth Refueling Outage, with the remainder scheduled to be tested 18 months later during the Sixth Refueling Outage. This was discussed with the Bulletin's Technical contact in I&E, and found to be marginally acceptable. Further discussions with DLC management indicated that the station would make a reasonable effort to accelerate the test schedule during any intervening outages. This was found acceptable.

In the submittal, the licensee stated that differential pressure testing should be minimal, since the valves were previously tested to demonstrate stroke time compliance at design differential pressure prior to shipment from the valve manufacturer. Justification on a case-by-case basis that includes an alternative method where such design differential pressure testing cannot be practically performed, was not provided. The inspector discussed this approach with the Technical Contact referenced in the bulletin and informed the licensee that a supplemental response should be issued providing more specific information, as previous vendor testing alone is not a sufficient bases. These comments were acknowledged.

The licensee committed to modify the electrical corrective maintenance procedure (CMP-1-75-79) to record the as-found and as-left switch settings by June 30, 1987. This item remains open until the CMP is revised with the new data and approved for use. The inspector noted that it already recorded some of the as-found and as-left switch settings and defined an acceptance band based on a previous engineering review.

12. Exit Interview

Meetings were held with senior facility management periodically during the course of this inspection to discuss the inspection scope and findings. A summary of inspection findings was further discussed with the licensee at the conclusion of the report period.