U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.: 50-334/88-16 License Nos.: DPR-66
50-412/88-11 NPF-73

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

Facility Name: Beaver Valley Power Station, Units 1 and 2

Location: Shippingport, Pennsylvania

Dates: April 1 - 30, 1988

Inspectors: J. E. Beall, Senior Resident Inspector
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Approved by: Lowell E. Tripp 5/16/88
Lowell E. Tripp, Chief Date
Reactor Projects Section No. 3A

Inspection Summary: Combined Inspection Report Nos. 50-334/88-16 and 50-412/88-11 - April 1 - 30, 1988.

Areas Inspected: Routine inspections by the resident inspectors of licensee actions on previous inspection findings, plant operations, physical security, radiological controls, plant housekeeping and fire protection, maintenance, surveillance testing, calibration program and review of periodic and special reports.

Results: No violations, unresolved items or significant concerns were identified by NRC. A licensee identified violation involving the failure to perform containment isolation valve closure surveillance testing for three normally closed valves is discussed in Detail 4.3. Followup and closure of an allegation regarding piping stress analyses is discussed in Detail 8. Five NRC open items were closed during this inspection (Detail 3).

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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. Summary of Facility Activities

At the beginning of the inspection period, both Unit 1 and Unit 2 were at 100% power. On April 4, 1988, Unit 2 tripped from full power due to low reactor coolant system flow following the de-energization of the "A" reactor coolant pump (see Section 4.2.1). Unit 2 was returned to power on April 5, 1988. Both Unit 1 and Unit 2 were at 100% power at the close of the inspection period.

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/completed licensee actions were discussed for the items reported below:

3.1 (Closed) IFI (50-334/84-25-02): Determine whether Technical Specifications need to be updated for the containment emergency air lock (EAL). The licensee previously determined that containment and outdoor temperature parameters were limiting conditions for nil ductility limits of the metal used in construction of the EAL. To address operability concerns for the EAL, the licensee administratively maintained the EAL out of service during cold weather. The licensee recently decided to insulate the outer EAL door which would eliminate both the nil ductility concerns and the need for revised Technical Specification requirements, provided that the insulation is administratively verified to be intact prior to or during cold weather. The insulation would be removed when the EAL is physically taken out of service (during outages), a process which necessitates the implementation of administrative controls to ensure that the insulation is properly replaced. The licensee expects to implement the EAL insulation effort during the Fall 1988 prior to extreme cold weather. The inspector will review the licensee's actions during a future inspection. This item is closed.

3.2 (Closed) IFI (50-334/85-24-02): Review licensee actions to improve feedwater regulating valve (FRV) reliability. The licensee has experienced FRV control problems since initial plant startup. Several modifications have previously been implemented, but they have not been effective in eliminating the control problems. During the licensee's sixth refueling outage (December 1987 - March 1988), Design Change Package (DCP) No. 829, BVPS-1 Feedwater System Upgrade, was completed to implement the feedwater system task force recommendations to resolve the FRV control problems. The major change from the DCP was to reduce the diameter of the main feedwater pump impeller to lower the pressure drop across the FRVs. Additionally, the FRV cage and plug (trim) assemblies were re-sized to match the new pump and system characteristics. After approximately two months of operation following implementation of the design change, no control problems have been experienced with the FRVs. It should be noted, however, that the majority of the FRV control problems have been experienced toward the end of the operating cycle. The inspector will review the effectiveness of the licensee's modification through the routine inspection program during subsequent plant operations. This item is closed.

3.3 (Closed) Violation (50-334/87-07-01): Failure to shut the "1C" gaseous waste system sample return valve, resulting in an unplanned gaseous waste release. The licensee responded to the violation by letter dated October 9, 1987. The inspector verified that the licensee's commitments have been implemented, including the issuance of special instructions to shift personnel to require that senior control staff review and verify specific checks and alignments prior to both gaseous and liquid discharges. This item is closed.

3.4 (Closed) Unresolved Item (50-334/87-07-05): Determine safety significance of non-conservative overpressure protection system (OPPS) setpoints and investigate discrepancies between NRC safety evaluation report (SER) assumptions and Technical Specification requirements for ESF/Reactor Protection System components. The licensee performed an evaluation to address the reactor coolant system overpressurization concerns of the May 27, 1987 event, when the licensee identified that the OPPS trip setpoints were actually at 364 psig, 14 psig higher than the Technical Specification required value of 350 psig. The evaluation adequately demonstrated that there was no safety impact due to the event. The OPPS setpoint specification appears to be unique in that a "nominal" setpoint value is specified in Technical Specifications. The NRC SER used 350 psig as the maximum value, including instrument error, while the licensee used a nominal value of 350 psig plus instrument error. Other ESF and Reactor Protection System trip/actuation setpoints are not susceptible to similar inconsistencies as both the Trip Setpoints and associated Allowable Values are specified in the Technical Specifications. No additional concerns were identified. This item is closed.

3.5 (Closed) Unresolved Item (50-412/87-68-01): Address the potential design deficiency in the BV-1 Fast Transfer System for switching from on-site to off-site power and vice versa. On November 17, 1987, BV-2 experienced a loss of off-site power following a turbine trip due to an inadvertent turbine thrust bearing signal. It was subsequently determined that three design deficiencies contributed to the sequence of breaker operations that resulted in the loss of off-site power event. The inspectors questioned whether similar design deficiencies may exist in BV-1. The licensee's followup study of the system design indicated that some of the BV-1 design features were similar to BV-2. A design change (DCP No. 867) was initiated in December 1987 to correct these apparent design deficiencies. The scope of the design change included: (a) the replacement of four turbine trip MG-6 relays (62ASTX 1&2, 162ASTX 1&2) with high speed latching relays to maintain a turbine trip signal once it is executed; (b) the installation of knife switches in the closing coil circuits for circuit breakers 41A, 41C, 141A, 141C, 241B 241D, 341B and 341D located in the fast bus transfer breaker cabinets. Installation of this design change was completed during the 1987 refueling outage and the modified system was tested successfully on January 8, 1988.

The inspector reviewed pertinent documents in DCP No. 867, including:

a. Specification No. 8700-DES-0239 "Specification for installation of fast bus transfer breaker switches and turbine latching relays" (Revision 1), dated December 30, 1987.

b. Temporary Operating Procedure No. 1-88-02 "Fast bus transfer testing for DCP 867" (Revision 1), dated January 15, 1988.

The inspector also physically observed the installed conditions of the latching relays and the knife switches in the switchgear area and did not identify any deficiencies. The licensee's corrective action is considered adequate and this item is closed.

4. Plant Operations

4.1 General

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

-- Control Room	-- Safeguard Areas
-- Auxiliary Building	-- Service Building
-- Switchgear Area	-- Diesel Generator Buildings
-- Access Control Points	-- Containment Penetration Areas
-- Protected Area Fence Line	-- Yard Area
-- Turbine Building	-- Intake Structure

4.1.1 Component Labeling

During a routine plant tour, the inspector noted that the label for a control transfer switch was missing from the emergency shutdown panel (SDP). The SDP is to be used if the control room becomes inaccessible (e.g., due to a control room fire). The label that was missing appeared to be for the control transfer to the SDP for the "2B" Control Rod Drive Mechanism Shroud Fan (1VS-F-2B). The inspector also noted that about five other labels had become unglued from the SDP benchboard although they were still physically in place. The inspector brought this concern to the licensee's attention who committed to resolve the discrepancies. Inspector followup on this issue will be included with the followup inspection associated with NRC Unresolved Item No. 50-334/88-11-01, Inadequate Plant Labeling.

4.1.2 ESF System Walkdown

The operability of selected Engineered Safety Features (ESF) systems were verified by performing walkdowns of the accessible portions of the systems. The inspectors confirmed that system components were in the required alignments, instrumentation was valved in with appropriate calibration dates, as-built prints reflected the as-installed systems and the overall conditions observed were satisfactory. The systems inspected during this period include the Recirculation Spray, Emergency Diesel Generator and Quench Spray systems. No concerns were identified.

4.2 Operations

During the course of the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration and plant conditions. During plant tours, logs and records were reviewed to determine if entries were properly made, and that equipment status/deficiencies were identified and communicated. These records included operating logs, turnover sheets, tagout and jumper logs, process computer printouts, unit off-normal and draft incident reports. The inspector verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. In general, inspector comments or questions resulting from these reviews were resolved by licensee personnel. In addition, inspections were conducted during backshifts and weekends on the following dates and times: 4/5, 4:15 am - 7:00 am; 4/9, 8:30 am - 10:30 am; 4/16, 10:00 am - 4:00 pm; 4/17, 9:00 am - 3:00 pm; 4/24, 10:00 am - 5:45 pm; 4/30, 2:00 pm - 9:00 pm. The inspectors verified that plant operators were alert and displayed no signs of fatigue or inattention to duty.

4.2.1 Reactor Trip Due to Low RCS Flow

On April 4, 1988, Unit 2 tripped from 100% power due to low reactor coolant system (RCS) flow. The low flow condition occurred during the performance of Operations Surveillance Test (OST) No. 2.36.18 (4kV and 480 Volt Normal Bus Undervoltage Test), when the operability of the "2A" non-emergency 4KV bus undervoltage protection system was being verified. During the test, the undervoltage relays actuated, causing several motor loads to automatically isolate from the bus, including the "A" reactor coolant pump (RCP). Upon the loss of the RCP, an immediate reactor trip occurred as a result of the reduced RCS flow. Emergency operating procedures were used by plant operators to stabilize the plant in Mode 3 (Hot Standby) following the reactor trip. The licensee made the required notifications per 10 CFR 50.72 reporting requirements.

Following the reactor trip, the licensee initiated troubleshooting activities of related plant equipment, and identified that the cause of the event was due to the failure of the undervoltage blocking relay. Upon placing the undervoltage test circuit in the "Test" position, the blocking relay is designed to pick up, thus preventing the simulated undervoltage signal from actuating the associated equipment. The relay failure was apparently caused by insufficient latching of one set of relay contacts. The licensee adjusted the blocking relay contacts and inspected additional similar relays for additional problems. No deficiencies were identified during the inspection.

Additional licensee action included initiating a review to determine the reason for performing OST 2.36.18 on a monthly frequency. No Technical Specification requirements or NRC commitments to perform the OST were found and the OST is classified as a balance of plant surveillance activity. Therefore, the licensee elected to discontinue the performance of the OST on a monthly frequency and currently plans to perform it only when the plant is shutdown. This action was taken to reduce the potential for unnecessary safety system challenges. The Technical Specification undervoltage protection system utilizes a different type of relay and they are tested monthly per Technical Specification surveillance requirements. No additional concerns were identified.

4.2.2 Containment Isolation Valve Inoperability

On April 5, 1988, during a procedure review/revision, the licensee identified that Unit 1 containment isolation phase A (CIA) valves TV-1FP-105, TV-1FP-106, and TV-1FP-107, were not included in the 18 month Operations Surveillance Test (OST) No. 1.1.4, Containment Isolation Trip Test, CIA Train B (Revision 62). Plant drawings were reviewed and the licensee confirmed that the three valves do receive a CIA Train B isolation signal. Upon notification, plant operations personnel immediately declared the three valves inoperable due to the failure to meet the surveillance requirement of Technical Specification 3.6.3.1. The associated Action Statement for Technical Specification 3.6.3.1 requires that inoperable containment isolation valves be restored to operable status within four hours or isolate the affected penetration. In accordance with Action Statement requirements, the licensee de-energized and closed the valves within four hours of identification of the problem. The valves are containment fire protection header isolation valves, and receive an automatic close signal when a CIA occurs. The valves are normally maintained closed during plant operation.

Immediate licensee corrective action included initiating operating manual deficiency reports for the affected procedures to include the three CIA valves. Additionally, a review was initiated to confirm that all other CIA valves are listed in surveillance test procedures and have been fully tested. No other deficiencies were identified. Additionally, the licensee is developing a temporary operating procedure that will verify that these valves will stroke closed upon receiving a Train B CIA signal.

Licensee review into past performances of OST 1.1.4 indicate that the affected valves were never included in the procedure. It was determined that the CIA valves were installed as a part of a larger plant modification in 1982. At that time, the station procedure update/revision process following plant modification was as follows. After implementation of the design change and issuance of the Technical Specification Amendment (if applicable), the various station groups would receive a letter describing the change made to the plant. The station groups were then responsible to revise the appropriate procedures. The licensee determined that the procedure change required by the plant modification in 1982 was omitted by the licensee at that time, therefore, the procedures were not revised to include the three CIA valves. The current procedure upgrade process includes the various station groups from the beginning of the project (Design Concept phase). The station groups are continually updated on modification development, personnel involvement begins at an earlier time, and the groups responsible for procedure changes have specific guidance and checklists to aid in determining whether station procedures need to be revised.

To provide assurance that additional problems had not previously occurred under the old plant modification procedure system, the licensee instituted a review of randomly selected design change packages from between 1980 and 1982. Of the approximately 127 DCPs performed, about one-third of them were reviewed. No similar problems were identified.

Since the licensee identified this failure to meet Technical Specification surveillance requirements and this situation meets the criteria to be considered a licensee identified violation, in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR 2, Appendix C, no Notice of Violation will be issued.

4.3 Plant Security/Physical Protection

Implementation of the Physical Security Plan was observed in various plant areas with regard to the following:

-- Protected Area and Vital Area barriers were well maintained and not compromised;

-- Isolation zones were clear;

-- Personnel and vehicles entering and packages being delivered to the Protected Area were properly searched and access control was in accordance with approved licensee procedures;

-- Persons granted access to the site were badged to indicate whether they have unescorted access or escorted authorization;

-- 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 illumination was maintained.

No deficiencies were identified.

4.4 Radiological Controls

Posting and control of radiation and high radiation areas were inspected. Radiation Work Permit compliance and use of personnel monitoring devices were checked. Conditions of step-off pads, disposal of protective clothing, radiation control job coverage, area monitor operability and calibration (portable and permanent) and personnel frisking were observed on a sampling basis. No concerns were identified.

4.5 Plant Housekeeping and Fire Protection

Plant housekeeping conditions including general cleanliness conditions and control and storage of flammable material and other potential safety hazards were observed in various areas during plant tours. Maintenance of fire barriers, fire barrier penetrations, and verification of posted fire watches in these areas were also observed. The inspector conducted detailed walkdowns of the accessible areas of both Unit 1 and Unit 2.

4.5.1 Unit 1 Areas

During the previous inspection, the inspector expressed the concern that housekeeping at Unit 1 exhibited weakness. During the current inspection period, the inspector noted substantial improvements in housekeeping in both radiologically controlled areas and other plant areas. Areas noted to be dirty were cleaned, and litter was removed. Individual deficiencies were identified to the licensee for continued cleanup.

4.5.2 Unit 2 Areas

During the current inspection period, the inspector noted that Unit 2 maintained a very good level of housekeeping. Isolated deficiencies were identified to the licensee for resolution.

5. Maintenance

The inspector reviewed selected maintenance activities to assure that:

-- the activity did not violate Technical Specification Limiting Conditions for Operation and that redundant components were operable;

-- required approvals and releases had been obtained prior to commencing work;

-- procedures used for the task were adequate and work was within the skills of the trade;

-- activities were accomplished by qualified personnel;

-- where necessary, radiological and fire preventive controls were adequate and implemented;

-- QC hold points were established, where required, and observed;

-- equipment was properly tested and returned to service.

Maintenance activities reviewed included:

MWRs 880604, 880605, 880606: Rezero I/P Output Drift for Atmospheric Steam Dump Valves.

No deficiencies were identified.

6. Surveillance Testing

The inspectors witnessed/reviewed selected surveillance tests to determine whether properly approved procedures were in use, details were adequate, test instrumentation was properly calibrated and used, Technical Specifications were satisfied, testing was performed by qualified personnel and test results satisfied acceptance criteria or were properly dispositioned. The following surveillance testing activities were reviewed:

BVT 1.3 - 8.3.1	Incore Moveable Detector Flux Mapping
OST 1.6.2	RCS Water Inventory Balance
OST 1.6.7	Accident Monitoring Instrumentation Channel Checks
OST 1.11.1	Safety Injection Pump Test

OST 2.7.5	Centrifugal Charging Pump Test
OST 2.11.3	Boron Injection Flow Path Valve Position Verification
OST 2.13.8	Containment Depressurization System Position Verification - Train A

No deficiencies were identified.

7. Calibration Program

The licensee's calibration program uses red foil-type stickers to identify those components required by TS to be calibrated within a specific period. Certain components which are used to measure the performance of other TS required equipment are also given red foil-type stickers. In previous inspections, the inspector noted that certain of these stickers had been identified to the licensee as being beyond the required calibration due date. The inspector also identified instances where identical components had been assigned different kinds of calibration stickers.

In all but one case, the deficiencies were administrative in nature such as wrong sticker (should not have been red), or wrong calibration due date (wrong year). The one instrument found to be beyond its calibration due date was still within the "grace" period allowed by the Technical Specifications. The instrument was promptly recalibrated and the inspector confirmed that the device was in the licensee's tracking system. This item was the only deficiency among several hundred items reviewed and is considered an isolated case.

No violations were identified.

8. Overstressed Piping Allegation (RI-88-A-0017)

In 1979, the NRC issued several IE Bulletins concerning generic problems in the seismic stress analyses of safety related piping. Certain non-conservative factors were discovered concerning information input for seismic analyses and these were addressed in IE Bulletin 79-02 (pipe supports) and 79-04 (valve weights). During the evaluation of certain piping designs, significant discrepancies were identified at certain facilities between original piping analyses and the then (1979) acceptable computer analysis code. These discrepancies (see IE Information Notice 79-06) led to the NRC issuance of IE Bulletin 79-07 which required all power reactor facilities to verify that the analysis codes used were properly benchmarked for accuracy. Four sites (including Beaver Valley Unit 1) were issued show cause orders and Beaver Valley Unit 1 underwent a five-month outage to address this seismic stress issue.

The confirmation of seismic analysis input information to actual, as-built (and possibly modified) system configuration was the subject of IE Bulletin 79-14 which was issued to all power reactor facilities. This Bulletin was a major contributor to another long (nearly 12 months) shutdown for Beaver Valley Unit 1. During the extended outage, the licensee employed two contractors, Nuclear Services Corporation (NSC) and Schneider Consulting Engineers (SCE), to supplement the extensive analysis effort of Stone & Webster Engineering Corporation, the architect-engineer.

During the reanalysis effort, many examples of piping which could become overstressed under certain conditions were identified by the engineers conducting the reanalysis. These deficiencies were forwarded to the licensee by the company making each identification. The licensee reviewed each deficiency and made a determination of reportability to the NRC as part of the corrective action. The inspector reviewed several examples of correspondence which transmitted potentially reportable deficiencies from the identifying contractor to the licensee. The licensee made many Licensee Event Reports (LERs) during the reanalyses effort, each of which reported the identification of a potentially overstressed condition involving safety related systems. In 1980 alone, approximately 25 LERs of this nature were submitted. Other similar LERs were submitted in 1979 and 1981. The inspector reviewed a sample of these LERs and no deficiencies were identified. The volume of such LERs provides good evidence that all deficiencies that met the licensee's criteria for reportability were reported.

On March 23, 1988, the NRC requested the licensee to review one particular deficiency referred to in an unsigned, SCE internal memo dated December 24, 1980. The licensee's response, dated April 13, 1988, and the supporting documents were reviewed by the inspector. The inspector, following the independent review, concluded that the deficiency involved was not reportable to the NRC because the piping involved was not safety related nor would its failure have impacted safety related components. The inspector noted that the deficiency had been corrected as part of a plant modification at that time.

The inspector also reviewed the process which had been in place during the reanalysis effort to identify deficiencies, forward them to the licensee, review them for reportability, and correct them in the field. Extensive documentation exists on these activities including system drawings, piping isometrics, meeting minutes, inter-company correspondence, design change files and NRC reports. The inspector reviewed a sample of each class of documentation including all available information on the deficiency involved in the allegation.

No deficiencies were identified; this allegation is closed.

9. Review of Periodic Reports

Upon receipt, periodic reports submitted pursuant to Technical Specification 6.9 (Reporting Requirements) are reviewed. The review assessed whether the reported information was valid, included the NRC required data and whether results and supporting information were consistent with design predictions and performance specifications. The inspector also ascertained whether any reported information should be classified as an abnormal occurrence. The following reports were reviewed:

-- BV-1/BV-2 Monthly Operating Report for Plant Operations from March 1-31, 1988.

-- BV-1/BV-2 1987 Annual Radiological Environment Report

No deficiencies were identified.

10. 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 on May 12, 1988.