U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.:	50-334/89-05 50-412/89-05	License Nos.:	DPR-66 NPF-73

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

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

Location: Shippingport, Pennsylvania

Dates: April 1 - May 22, 1989

Inspectors: J. E. Beall, Senior Resident Inspector
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Approved by: Lowell E. Tripp 6/6/89
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Reactor Projects Section No. 3A
Division of Reactor Projects

Inspection Summary: Combined Inspection Report Nos. 50-334/89-05 and 50-412/89-05 for April 1 - May 22, 1989

Areas Inspected: Routine inspections by the resident inspectors of licensee actions on previous inspection findings, plant operations, security, radiological controls, plant housekeeping and fire protection, surveillance testing, maintenance, inoperable seismic instrumentation, steam generator tube plugging, AMSAC operational problems and licensee event reports.

Results: No violations or unresolved items were identified. Personnel related errors as discussed in the last Resident Inspection Report continued to create operational challenges to the plant (Sections 4.3.1, 4.3.3 and 4.3.5). A personnel radiological safety concern was raised and resolved (Section 4.5). Certain seismic monitors were found to have been degraded for approximately two years and were corrected (Section 7). A steam generator tube failure at a different site led to prompt licensee preventive measures (Section 8). One reactor trip and safety injection was found to be due to a potentially generic design flaw (Section 9). Two previously open NRC items were closed during this inspection.

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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 period, Unit 1 was at 100% power and Unit 2 was defueled and in the first refueling outage. During the period, Unit 1 returned to a core life extension schedule which involved operating at 90% during the week and 50% on the weekend. Unit 2 completed the outage, loaded fuel and began plant startup. Unit 2 reached Mode 2, conducted low power physics testing, then experienced problems with the reactor vessel level indicating system, and returned to Mode 5 at the end of the period. Unit 1 experienced a reactor trip and safety injection from 89% power on May 18 (see Sections 4.3.6 and 9). Unit 1 corrected the problem, restarted and was at 90% power at the end of the period.

3. Status of Previous Inspection Findings

The NRC Outstanding Items 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 item reported below.

3.1 (Closed) Unresolved Item (50-334/87-12-01): The licensee was to resolve a potentially generic issue concerning a new postulated sequence of events that were potentially more severe than the Condition II events analyzed in the Final Safety Analysis Report. The postulated sequence of events involved a turbine trip event with a consequential loss of forced reactor coolant flow prior to a reactor trip. The Westinghouse Owner's Group evaluation (ESBU/WOG-89-052) concluded that the probability of the above scenario was too low to be considered as a Condition II evaluation and the licensee's offsite review committee concurred with that conclusion. This item is closed.

3.2 (Closed) Unresolved Item (50-412/88-16-01): Control room annunciators' power supply modification. On January 28, 1988, Unit 2 experienced a two hour loss of control room annunciators due to a fire. All annunciators were affected because the various circuits involved in the non-safety system had little circuit isolation. The licensee completed a modification which added circuit protection and isolation features designed to limit the effect of a component failure such that only a portion of the annunciators would be lost following one failure. The inspector reviewed the design package and maintenance work request and had no further questions. This item is closed.

4. Operational Safety

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
-- Reactor Containment	-- Spent Fuel Building

4.2 ESF Walkdown

The operability of selected engineered safety features systems was verified by performing detailed 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 Emergency Diesel Generator, Safety Injection and Recirculation Spray systems. No concerns were identified.

4.3 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, tag-out 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. Inspector comments or questions resulting from these reviews were resolved by licensee personnel. In addition, inspections were conducted during backshifts and weekends on 4/2, 4/12, 4/15, 4/18, 5/1, 5/2, 5/8, 5/13, 5/14, 5/15, 5/17, 5/20 and 5/21.

4.3.1 ESF Actuation (4/12)

The Unit 1 Control Room Emergency Bottled Air Pressurization (CREBAP) System automatically initiated on April 12 due to personnel error. During the performance of a surveillance test (OST 1/2.43.17A), the operator repositioned the wrong switch such that the test-generated high radiation signal was not blocked and the CREBAP system actuated. The procedure was clear and approved, and verbal communications were adequate. Licensee investigation also identified two human factor considerations which may have contributed involving the orientation of the switches and use of a common key (same key operates both switches). Operators verified no valid signal was present, reset the signal and normal system alignment was restored.

4.3.2 ESF Actuation (4/24)

A Unit 2 containment purge isolation occurred on April 24, due to airborne activity during decon activities in the reactor cavity. The fuel pool gate valve was found not to be fully shut (mechanically bound in a partly open position) which provided a ventilation path into the cavity (draft) and helped create the airborne problem. The licensee identified the cracked open valve, shut it fully and restored normal system lineup. No internal dose was received due to the event according to followup testing of potentially affected personnel.

4.3.3 ESF Actuation (4/27)

A Unit 2 emergency diesel generator (2-1 EDG) automatically started and loaded on April 27 due to personnel error during testing. The EDG and affected loads were secured and the normal lineup was restored. The event occurred during the testing of an undervoltage (UV) relay on charging pump 2CHS P21C. The technicians performing the test failed to defeat the output from the relay which went to the breaker powering one emergency bus (AE). The breaker tripped when the relay was UV tested, the bus was deenergized, and the 2-1 EDG auto-started to restore power to the AE bus. After troubleshooting activities, the 2-1 EDG was secured and normal lineup was restored.

4.3.4 Partial Flow Blockage in Unit 2 Recirculation Spray Heat Exchangers

Partial flow blockage was identified during surveillance testing of the Unit 2 recirc spray heat exchangers and reported on April 28. The test acceptance criteria specified a minimum flow rate of 12,000 gpm. Initial testing measured 11,923 and 8,406 gpm for the A and B trains respectively. The four heat exchangers were opened for inspection and the B and D heat exchangers (B train) were found to each contain about 25 pounds of Asiatic clams. The components and piping were cleaned and flushed; satisfactory flow rates were achieved prior to the end of the Unit 2 outage.

Long term corrective actions include placing the heat exchangers in dry layup during operation and use of a biofouling prevention agent in piping which must remain water filled.

4.3.5 Unit 2 Inadvertent Feedwater Isolation

On May 14, an inadvertent feedwater isolation occurred while performing Operating Surveillance Test (OST) 2.24.4, Steam Turbine Auxiliary Feed Pump Test. The OST was being performed to verify pump operability prior to entering Mode 3. The OST required that feedwater flow to all steam generators (SG) be greater than or equal to 700 gpm at a discharge pressure of at least 1133 psig.

After the pump had been manually started, the pump's discharge valve was slowly opened to admit flow to the steam generators. Due to previous turbine speed control problems, an operator, the Unit 2 shift supervisor and maintenance personnel were present at the pump to make any required adjustments to the turbine governor. Initial "B" SG level was 58% and in approximately one minute, the level in B SG had increased to about 70%. At that point, a control room operator notified the shift supervisor (located at the auxiliary feed pump) that "B" SG level was rapidly approaching the 75% feedwater isolation setpoint. The shift supervisor ordered an operator at the pump to shut the discharge valve and the shift foreman in the control room ordered a control room operator to shut the auxiliary feed flow control valve to "B" SG. About one minute later, "B" SG level reached 75% and a feedwater isolation occurred. All systems responded as designed to the feedwater isolation signal. The licensee made all required notifications to the NRC.

The licensee's preliminary investigation concluded that there were two major causes of the event. The first cause was the lack of adequate preplanning in that the B SG level was too high at the start of the test to permit sufficient time to perform the test. The second cause was poor communications in that the control room operator was not aware that the test run would be longer than normal due to planned turbine governor adjustments. The inspector noted that the OST contained no provisions to ensure adequate SG free volume prior to adding auxiliary feedwater. The inspector will review in a followup inspection the licensee's corrective actions.

4.3.6 Unusual Event

On May 18, 1989, an Unusual Event was declared following a safety injection (SI) signal which tripped the plant from 89% power. The SI was caused by high main steam line pressure rate of change following the opening of the load rejection steam dump valves. The cause of the event was determined to be a design flaw in the Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC) in that when the AMSAC panel was inadvertently deenergized, the load rejection steam dump valves opened initiating the event. For details, see Section 9.

No significant deficiencies beyond those discussed above were identified during inspector review and followup of these events.

4.4 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.

4.5 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. The recently installed equipment and measures for hot particle control appeared effective, in particular, the use of screening monitors.

The inspector observed portions of the core reload and identified an unsafe practice by a contractor (Westinghouse) technician. The individual was assisting in reload activities on the mobile fuel bridge which runs on tracks along the reactor cavity and projects across the cavity. The technician was observed by the inspector to walk across one beam (about 6 inches wide) above the water surface of the cavity. At that time, a fuel assembly was being reloaded and the bridge was over the reactor vessel. No safety line or any other measure was used for the 10 - 15 foot trip. The technician was wearing two sets of cloth protective clothing and two layers of plastic foot covers.

The bulky clothing, the multiple foot covers, and the beam narrowness were indicative of a need for protection against a slip or fall. The reactor cavity was filled with radioactively contaminated water (about 30 feet deep above the reactor vessel) possibly containing hot particles due to fuel movement. A fall would have resulted in immersion, contamination, possible ingestion of radioactive material and possible physical injury due to impact with the bridge or cavity wall.

The inspector observed the technician repeat the unsafe practice before reaching the immediate area (two round trips across the beam) and questioned the individual. The technician asserted that his actions were standard practice over many years. The inspector stated that the behavior was clearly unsafe and repeated this position to licensee senior management. The licensee's initial response indicated that the practice was not without precedent and was not viewed as particularly unsafe because the potential fall was only a few feet (into the contaminated water). After additional consideration, the licensee installed a safety line across the beam and used a harness type hookup to improve safety.

4.6 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.

Housekeeping in the Unit 2 radiologically controlled areas was impacted during the Unit 2 refueling outage. Weaknesses in housekeeping were noted in Containment (IR 50-334/89-06; 50-412/89-06). Walkdowns of other Unit 2 radiologically controlled areas revealed similar weaknesses in high activity areas. Areas were found littered with tools (such as wrenches, knives and flashlights), parts (such as gaskets, screws and washers) and debris (such as used gloves, cotton glove liners and paper swipes). The inspector discussed these problems with licensee management; all areas showed marked improvement near the end of the outage.

The inspector found the sump screen in the Unit 2 cable tunnel to be blocked. The sump, which is designed for fire fighting water removal, had a temporary screen under the floor grating which had become clogged. The inspector identified the problem to the licensee and the screen was removed.

5. 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:

OST 2.36.2 Emergency Diesel Generator (2EGS*EG2-2) Monthly Test, April 27, 1989.

OST 2.24.4 Steam Turbine Auxiliary Feed Pump (2FWE*P22), Test May 14, 1989.

OST 2.24.7 Steam Driven Auxiliary Feed Pump (2FWE*P22) Auto Start Test, May 14, 1989.

OST 2.36.1 Emergency Diesel Generator (EGS*EG2-1) Monthly Test, May 17, 1989.

No deficiencies were identified.

6. 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 commending 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:

-- MWR 892447 Install Temporary Modification to Turbine Impulse Pressure Channel III.

-- MWR 892448 Install Temporary Modification to Turbine Impulse Pressure Channel IV.

No deficiencies were identified.

7. Inoperable Seismic Instrumentation

During the troubleshooting of a system trouble alarm, the licensee discovered that two of the six site seismic monitors had incorrect settings for the functions associated with horizontal acceleration. An internal fault had been indicated by a response spectrum analyzer trouble alarm on April 1. These settings are designed to trigger alarms and to initiate event tape recording. The incorrect setpoints resulted from a surveillance procedure which contained incorrect values. The surveillance was last performed in May, 1987.

The licensee recalibrated the instruments, revised the procedure, and submitted a Special Report on April 24 as required by the facility Technical Specifications (TS 3.3.3.3.b). The inspector reviewed the report and other associated documents and noted that four of the six monitors were fully functional during the period and the two degraded monitors would have been triggered by vertical motion as designed. The Technical Specifications state (TS 3.3.3.3.c) that the immediate shutdown requirements (TS 3.0.3) are not applicable, so the facility was not operated in violation of the Operating License. The facility did, however, operate for a prolonged period (nearly 2 years) with a degraded ability to detect and monitor seismic events. In discussions with the inspector, the licensee agreed that this event highlighted the need to carefully review and perform infrequent surveillance procedures.

8. Steam Generator Tube Plugs

On February 25, 1989, North Anna, Unit 1, experienced a steam generator tube leak caused by the mechanical failure of a tube plug. The plug cracked and the top portion was propelled by RCS pressure up the empty tube. The missile punctured the tube at the bend at the top and also damaged an adjacent tube. The event was the subject of NRC Information Notice No. 89-33, "Potential Failure of Westinghouse Steam Generator Tube Mechanical Plugs."

Investigation revealed that certain heats of thermally treated Inconel 600 were susceptible to Primary Water Stress Corrosion Cracking (PWSCC). Other facilities also identified examples of cracked tube plugs. These findings led to the issuance of NRC Bulletin No. 89-01, "Failure of Westinghouse Steam Generator Tube Mechanical Plugs" on May 15. The Bulletin requested site-specific data and required several actions involving tube plug repair/replacement.

Unit 1 contains six tubes (all in "A" Steam Generator) with plugs fabricated from Bulletin-identified heats. The licensee plans to repair/replace these plugs during the next refueling outage scheduled to begin on September 1, 1989, which complies with the Bulletin. Unit 2 was in the first refueling outage when the material factors of the North Anna, Unit 1, event became available. Unit 2 had 9 tubes plugged with affected materials. The plugs in the higher temperature side (TH) were repaired during the outage using the "plug within a plug" method. The PWSCC rate increases with temperature so the remaining tube plugs are much less sensitive to PWSCC and substantial margi.. (over 5000 effective full power days) is present.

The inspector found the actions taken by the licensee in response to the plug failure events to be good. Particularly noteworthy was the licensee's prompt actions in the midst of an ongoing Unit 2 refueling outage which enabled the repair of the most potentially vulnerable tube plugs on Unit 2.

9. <u>Unit 1 Safety Injection and Reactor Trip Following De-energization of AMAC</u>

The inadvertent down powering of the Unit 1 Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC) panel resulted in a reactor trip and a safety injection (SI) with flow On May 18, 1989, a technician inadvertently opened the electrical supply breaker to the Unit 1 AMSAC panel which caused ten of the mainsteam dump valves to open. This rapidly lowered main steam pressure causing a high steam line pressure rate safety injection actuation and subsequent reactor trip.

The control room operators responded to the event in accordance with the licensee's emergency operating procedures. The high head safety injection pumps injected into the reactor coolant system and an Unusual Event was declared. The operators terminated safety injection within 10 minutes and stabilized the plant in Hot Standby (Mode 3) after the steam dump valves shut when reactor coolant average temperature dropped below 543 F (low-low Tavg). The Unusual Event was terminated approximately 40 minutes after the event.

AMSAC was installed in Unit 1 in response to 10 CFR 50.62 "Requirements for Reduction of Risk from ATWS Events for Light-Water Cooled Nuclear Power Plants." AMSAC provides a non-safety-related backup system which is diverse and independent from the reactor protection system. AMSAC is designed to assure that the RCS will not be overpressurized during an ATWS event by providing a backup turbine trip and an initiation of auxiliary feedwater. Unit 1's AMSAC system was designed by Foxboro to be compatible with the Westinghouse 7100 Series process instrumentation system.

The five input signals to AMSAC include feed flow (3 signals) and turbine impulse pressure (2 channels). One of the pressure signals was generated by PT-1MS-446. The signal from this transmitter after passing through a signal isolator, provided input signals to other non-safety-related process instrumentation control circuits beside AMSAC via a current loop. These circuits were connected in series. Another process instrumentation control circuit that utilized the signal from PT-1MS-446 was a signal summator which computed the temperature error for the load rejection steam dumps. The other pressure signal was generated by PT-1MS-447. One of the control circuits on this process instrumentation current loop was a lead-lag controller which transmitted the rate of decrease of turbine impulse pressure to signal circuit comparators which, in turn, tripped at 15% and 50% load rejection arming the steam dumps.

When the AMSAC panel was de-energized, a very large resistance was introduced to the current loops which provided input to the panel. This, in turn, caused the current in these loops to drop essentially to zero (acted like an open circuit). Therefore, the load rejection bistables armed and the temperature error signal to the load rejection steam dump went to its maximum value. The load rejection steam dump valves then fully opened as designed, initiating the event.

As a corrective action, the licensee modified the process instrumentation circuitry to make the turbine impulse pressure signals to the load rejection circuits independent of AMSAC. Spare signal isolators were utilized to route separate turbine impulse pressure signals to the load rejection circuits. The licensee elected not to modify the feedwater flow signals since there were no adverse effects on plant operation when these signals dropped to zero (indication only). Post-modification testing confirmed that de-energizing AMSAC would no longer affect the load rejection circuitry.

The licensee verified that the Unit 2 load rejection circuitry was unaffected by the Unit 2 AMSAC system by de-energizing the panel while the plant was shutdown. Unit 2's AMSAC system was also designed by Foxboro, but was designed to be compatible with the Westinghouse 7300 Series process instrumentation system utilized in Unit 2.

The inspector found licensee's actions in response to this event, including investigation, troubleshooting modification and testing, to be very good.

10. Inoffice Review of Licensee Event Reports (LERs)

The inspector reviewed LERs submitted to the NRC Region I Office to verify that the details of the event were clearly reported, including 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:

Unit 1:

LER: 89-02-00 Reactor Trip Due to Feedwater Regulating Valve Malfunction.

LER: 89-03-00 Inadvertent CREBAPS Actuation Due to Radiation Monitor Failure.

LER: 89-04-00 Inadvertent ESF Actuation.

LER: 89-05-00 River Water Pump Auto-Start - ESF Actuation.

Unit 2:

LER: 89-03-00 Reactor Trip Due to Main Feedwater Regulating Valve Failure.

LER: 89-04-00 Informational Report Providing Clarification of a 10 CFR 50.72 Notification.

LER: 89-05-00 Inadvertent Safety Injection.

LER: 89-06-00 Expansion Joint Liner Failures for Component Cooling Pumps.

LER: 89-07-00 Leak Collection Ventilation Flowpath Automatic Realignment Actuation.

LER: 89-08-00 Pressurizer Code Safety Valve Lift Setting Less Than Technical specification Limit

LER: 89-08-01 Revision to LER 89-08.

LER: 89-09-00 Degraded High Energy Line Break (HELB) Temperature Elements.

The above LERs were reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. The LERs were found to be of high quality with good documentation of event analyses, root cause determinations and corrective actions. The inspector verified that the licensee had a procedure for the periodic inspection of reach rod operated valves (Unit 1 LER 89-05). The failed valve had been inadvertently omitted from the procedure due to its location in an outlying building; the licensee had taken steps to add the valve and confirm that no other valves were similarly omitted. The licensee committed to check for loose parts in the Unit 2 steam generators during the first refueling outage (Unit 2 LER 89-03). The inspection was performed and no loose parts were identified. The licensee concluded that not declaring an Unusual Event (Unit 2 LER 89-05) was correct; the inspector forwarded the appropriate documents for specialist followup. The technical position on PORV operability (Unit 2 LER 89-04) determination was also designated for further review.

11. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. No new unresolved items were identified in this inspection report.

12. Meetings

Periodic meetings were held with senior facility management 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 June 2, 1989.