U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos. 50-334/89-23
50-412/89-22

License Nos. DPR-66
NPF-73

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

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

Location: Shippingport, Pennsylvania

Dates: November 18 - December 31, 1989

Inspector: P. R. Wilson, Senior Resident Inspector

Approved by: Francis Young 2/15/90
Francis Young, Acting Chief, Date
Reactor Projects Section No. 4B
Division of Reactor Projects

Inspection Summary: Combined Inspection Report Nos 50-334/89-23 and 50-412/89-22 for November 18 - December 31, 1989.

Areas Inspected: Routine inspections by the resident inspector of licensee actions on previous inspection findings, plant operations, security, radiological controls, plant housekeeping and fire protection, surveillance testing, maintenance, unlocked high-high radiation barrier door, safety injection actuation, feedwater isolations, freezing instrument lines, and licensee event reports.

Results: Overall, the facility was operated safely. One violation was identified regarding the failure to follow procedures which resulted in a Unit 1 safety injection actuation (section 8). One non-cited violation was identified regarding an unlocked door to a high-high radiation area (section 7). The operator's actions regarding a fire in a Unit 1 Emergency Diesel Generator Engine Start Cabinet were notable (section 4.3.2). Weaknesses were identified regarding the automatic opening of a Unit 1 reactor trip breaker (section 4.3.4). Two unresolved items were identified concerning three Unit 1 Feedwater Isolations (sections 4.3.3 and 9.0). Improvement in Unit 1 housekeeping was observed (section 4.6). Licensee's actions concerning the freezing of Unit 2 instrument lines were reviewed. No deficiencies were identified (section 10). Three previous open NRC items were reviewed. Two items were closed during this inspection.

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*Indicates the NRC Inspection Procedure used to inspect the area identified

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 in Mode 5 (Cold Shutdown) for the seventh refueling outage and Unit 2 was operating at 100% power. On December 16, Unit 2 reduced power to 85% power as part of a core life extension schedule which involved operating at 85% power for a six week period. Unit 2 operated at 85% power throughout the remainder of the period. During the period, Unit 1 completed the outage and returned to power operations on December 26. On December 27, Unit 1 tripped from 29% power following the loss of power to the operating Rod Drive Motor Generator (see Section 4.3.5). Unit 1 was restarted on December 27 and was operating at 50% power to 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 items reported below.

3.1 (Closed) Unresolved Item (50-334/85-20-03): Upgrade stores administrative controls to ensure critical parts are automatically reordered prior to depletion. This item was subsequently reviewed in Inspection Report 50-334/88-01; 50-412/88-01 and remained open pending the implementation of a computer program to automatically generate listings when parts need to be reordered. The licensee has completed the implementation of this program.

3.2 (Closed) Violation (50-334/88-12-01): Two of four high-high containment pressure channels had not been operable during operation due to the placement of the associated bistables in the bypassed condition. This condition, which existed for approximately eight days, involved exceeding a Limiting Condition for Operation, which required a minimum of three operable channels for this function. The cause of the event was the performance of maintenance surveillance procedures (which left the bistables in the bypassed condition) after control room operators had performed a startup check verifying the bistables were in required position.

The inspector reviewed the containment high-high pressure bistable surveillance procedures. The procedures had been revised to require that the bistables be left in the as found condition at the end of the test. The revision further required that if the bistables were found bypassed at the start of the test, the nuclear shift supervisor was to be informed prior to placing the bistables in bypass.

The inspector also reviewed other selected maintenance surveillance procedures with respect to other solid state protection bistables. No deficiencies were identified.

The Unit 1 startup procedures were reviewed. The startup check list required that within eight hours prior to entry into Hot Shutdown (Mode 4) from Cold Shutdown (Mode 5), that the control room operators perform Operations Surveillance Test (OST) 1.50.1, "Mode 5 to Mode 4 Startup Prerequisites Verification." This OST contained steps to verify all protection instrumentation was properly aligned prior to escalation to Mode 4.

During the recovery from the seventh refueling outage, the inspector verified that the licensee had performed all the required protection system alignment checks prior to entry into Mode 4 within the required time limit.

The inspector found that the licensee's actions to prevent recurrence were adequate.

3.3 (Open) Violation (50-412/88-18/01): Failure to comply with Site Administrative Procedure (SAP) 17, "Reporting of Defects and Non-compliances." The plant manager was informed of a potential defect in three containment isolation valves ten months after the receipt of documentation identifying the suspected defect. However, SAP 17 required that the 10CFR21 analysis be completed and returned to the plant manager within 30 days. The inspector reviewed the licensee's corrective actions. SAP 17 was revised, assigning the responsibility for processing the tracking potential 10CFR21 issues to the Nuclear Safety Department (NSD).

SAP 17 requires that written reports be submitted to the NSD when defects and noncompliances are identified. Next, NSD assigns responsibility for evaluating the report for 10CFR21 concerns to the appropriate department manager. In addition, the NSD enters the concern into a tracking system with a 30 day response due date. Finally, the NSD provides a monthly status report to senior site management if the evaluation process is projected to exceed 30 days.

The inspector verified that potential 10CFR21 concerns once identified were being tracked and resolved in a timely manner. The inspector also verified that the monthly status reports to senior site management were being made as required. The inspector did find an instance where a vendor's written notification of a potentially defective overload relay heater was received by the licensee but was not forwarded to the NSD for processing and tracking for approximately six weeks. Even though subsequent evaluation determined there were no safety concerns relating to this notification, the delay in forwarding the reports to the NSD indicated an apparent weakness in the process of promptly identifying and evaluating potential 10CFR21 concerns.

Another corrective action taken to prevent recurrence was the issuance of Engineering Standard (ES)-A-1005, "Identification and Evaluation of 10CFR21 Concerns," which defines how 10CFR21 issues are to be identified, evaluated, and prioritized within the licensee's Engineering Department. The inspector found that some of the guidelines in the ES did not conform to the requirements of SAP 17. The guidance in the ES gives responsibility for evaluating and tracking potential 10CFR21 concerns to the manager of the Nuclear Engineering Department vice the manager of NSD as required by SAP 17.

This item remains open until the differences between SAP 17 and ES-A-1005 are resolved; and, the apparent weakness in the prompt identification of potential 10CFR21 concerns are corrected.

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.

The inspector conducted a detailed independent valve and breaker alignment check of the Unit 1 Auxiliary Feed System. The inspector identified some deficiencies in the licensee's "Power Supply and Control Switch List." The check list required that a breaker in a DC panel be closed to energize a Shutdown Panel transfer relay for three of the six AFW flow control valves. The breaker was designated as a spare and was found open. The most recently completed check list listed the breaker as being closed. Review by the licensee concluded the above breaker was a spare and should have been open. The relays were being energized using a breaker in a different DC distribution panel. Licensee review of this discrepancy is continuing.

The licensee submitted a procedure change request to correct the check list. The inspector discussed with the licensee the need to document and correct procedural inadequacies discovered during execution. The inspector had no further questions at this point of licensee review.

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, 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. Inspector comments or questions resulting from these reviews were resolved by licensee personnel. Onsite Safety Review Committee meetings were attend to evaluate the licensee's self-assessment capability. In addition, inspections were conducted during backshifts and weekends on 11/18, 12/09, 12/15, 12/19, and 12/20.

4.3.1 Unit 1 Inadvertent Challenge to Safety Systems While Shutdown

On December 13, 1989, a Unit 1 Train A reactor trip and safety injection signal were inadvertently actuated. At the time of the event, Unit 1 was in Cold Shutdown (Mode 5). The cause of the event was the failure to follow procedures. For more details see Section 8.0.

4.3.2 Unit 1 Relay Fire in the No. 2 EDG Engine Start Cabinet

On December 13, 1989, while in Cold Shutdown (Mode 5), a relay caught fire in the No. 2 Emergency Diesel Generator (EDG) Engine Start Cabinet. At the time, the No. 2 EDG had been running for approximately 10 minutes supplying power to its associated emergency bus as part of a surveillance test. A local operator, after observing smoke coming from the Engine Start Cabinet, immediately shut down the EDG. The local start circuit and alarm breakers were opened and the smoke exiting the cabinet ceased. The fire lasted for approximately two minutes. Core cooling was not affected since the required systems were energized from the redundant emergency bus.

The fire was traced to relay 52S1F7X (Westinghouse MG-6 series), which provides EDG start demand signal when the preferred feeder breaker to the 4160 V emergency bus automatically opens. Investigation determined that the source of the fire was the relay's reset coil. Further investigation determined that the reset coil failed to de-energize as designed due an insufficient gap between two contacts. The gap was found to be 0.003 inches while the required spacing should have been between 0.005 and 0.015 inches. This insufficient gap caused the reset coil to remain energized. The coil overheated and burned. The relay was replaced and subsequently satisfactorily tested. The licensee had instituted an inspection program of all MG-6 series relays in Unit 1 to verify proper gap settings following identification of similar concerns at Unit 2. The above relay had not yet been inspected.

The actions of plant operators to this event were notable, especially the quick response by the local operator in the EDG room whose prompt actions minimized the potential damage from the fire.

No unacceptable conditions were identified.

4.3.3 Unit 1 Feedwater Isolations

On December 15, 1989, while in Hot Shutdown (Mode 4), an inadvertent Feedwater Isolation (FWI) occurred due to drifting narrow range steam generator (SG) water level signals for the 1B SG. On December 16, while trouble shooting the cause of the above event, another FWI occurred. The two events were interrelated and are discussed in Section 9.0.

On December 18, 1989, while in Hot Standby (Mode 3), a FWI occurred due to high water level in the 1C SG. The event occurred while opening the 1C Main Steam Isolation Valve (MSIV). Prior to the event, the Main Steam piping had been warmed and pressurized via the MSIV bypass valves. To open the MSIVs, the differential pressure across the MSIVs was required to be less than 5 psid. To drop the differential pressure below 5 psid the control room operators cracked open the 1C SG Atomspheric Steam Dump Valve (ASDV). When the differential pressure decreased below 5 psid, the 1C MSIV was opened. The water level in the 1C SG swelled from 55% to 75% causing the FWI. The FWI was subsequently reset and the isolation valves were returned to the normal alignment.

The licensee's investigation into this event was not completed at the end of the inspection period. The licensee suspected that the 1C ASDV opened greater than desired while the MSIV was opened which in turn resulted in greater than expected swell. The inspector had no further questions.

4.3.4 Unit 1 Automatic Opening of a Trip Breaker

On December 21, 1989, while in Hot Standby (Mode 3) the "B" Reactor Trip Breaker automatically opened due to low steam generator (SG) coincident with a steam flow/feed flow mismatch. At the time, the "A" Reactor Trip Breaker was open.

Several activities were in progress at the time of the event. Surveillance testing of the Solid Station Protection System (SSPS) was being performed which required the "B" breaker Reactor Trip Breaker to be closed. Control Room operators were warming up the main steam piping via the 1A SG. In addition, technicians were trouble shooting the 1A feedwater flow transmitter which resulted in the generation of a steam flow/feed flow mismatch signal. With the above signal present, the SSPS trip set point for low SG level increased from 12% to 25%.

The event occurred when the water level in the 1A SG decreased below 25% due to inventory loss from the warming of the Main Steam piping. The control room operators who were distracted by other job related activities, failed to observe the decreasing SG level in time to prevent the level from dropping below the trip setpoint.

The cause of the event was inadequate attention was given to the decreasing level in the 1A SG. The control room operators were aware of the increased 1A SG level trip setpoint as it had been discussed prior to the Main Steam piping warmup evolution. Also, there was an apparent weakness in the supervision of control room activities in that the number of jobs assigned to the operators impacted the ability to adequately monitor SG level. The inspector considered this event not to be reflective of the licensee's normal ability to control plant evolutions. The inspector had no further questions.

4.3.5 Unit 1 Reactor Trip

On December 27, 1989, the Unit 1 reactor tripped from 29% power following initial startup from the seventh refueling outage. At the time of the trip, the rod control system was energized by one of the two rod drive motor generator (MG) sets. One MG set was out of service because post maintenance checks were not completed. The trip occurred when the supply breaker to the operating MG set tripped open, causing control rods to begin to drop as the MG set coasted down. The dropping control rods generated a power range high negative rate trip signal, causing the reactor trip. The control room operators responded as required by the Unit's Emergency Procedures.

The apparent cause of the MG supply breaker tripping open was a defective overcurrent trip device in the breaker. The breaker was subsequently replaced and the remaining post maintenance checks on the other MGs were satisfactorily completed. Both MG sets were returned to service and Unit 1 returned to power operation. All required NRC notifications were made. No unacceptable conditions were identified.

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.

During tours of Radiological Controlled Areas (RCA) of both units, the inspector identified discarded candy wrappers and cigarette butts indicating a potential ingestion of food and smoking in the RCAs, a violation of the licensee's work rules. Similar concerns were identified in several previous inspections (IR 50-334/89-03; 50-412/89-03, IR 50-334/89-18; 50/412/89-18, and 50-334/89-22; 50/412/89-21). In response to the above concern, the licensee issued a notice to all employees reiterating the work rules concerning eating, drinking, and smoking in RCAs and that any violators would be subject to dismissal. During tours late in the period, the inspector did not identify further examples of the above concern.

During the period, the inspector was informed of a Unit 1 radiological incident which occurred on November 1, 1989, concerning a closed door to a high-high radiation area (greater than 1000 mr/hr) that was found not locked as required. This event is discussed in Section 7.0.

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.

In the beginning of the period, general housekeeping in Unit 1 continued to decline. Paper trash, tape, cotton glove liners, rubber gloves, dirt, etc., were found in radiologically controlled areas. Later in the period, housekeeping in Unit 1 significantly improved. The licensee also made a notable effort to remove or secure loose equipment prior to plant startup from the outage. General housekeeping in Unit 2 was good throughout the period.

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:

BUT 1.47.2	Containment Integrated Leakage Rate Test
OST 1.45.11	Cold Weather Protection (Unit 1)
OST 2.45.11	Cold Weather Protection (Unit 2)
OST 1.24.4	Steam Driven Auxiliary Feed Pump Test
OST 1.36.4	Diesel Generator No. 2 Automatic Test
OST 1.26.8	Main Unit Overspeed Test

Unit 1 - Beaver Valley Test (BVT) 1.47.2 "Containment Integrated Leakage Rate Test" initially failed due to excessive leakage through Outside Recirculation Pump (RS-P-2B) seals and the fuel transfer tube blind flange. The RS-P-2B pump seals which had been replaced during the outage were replaced again and were satisfactorily tested. The fuel transfer tube blind flange was inspected and its inner gasket was found crushed in such a way as to permit the leakage of air, while at the same time blocked the Type B connection port (Type B Test performed prior to Type A Test indicated no leakage). The blind flange was reinstalled with new gaskets and was satisfactorily tested. The BVT was subsequently performed satisfactory.

No unacceptable conditions 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 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:

-- MWR 891549 - Repair of No. 2 Inverter
-- MWR 894378 - Replacement of Motor Generator Set Inboard Bearing

No deficiencies were identified.

7. Unit 1 Barricaded but Unlocked High-High Radiation Area Door

On December 1, 1989, the inspector was informed of a Unit 1 radiological incident which had occurred on November 1, 1989. The incident involved the discovery by the licensee during a routine surveillance check of all locked high radiation barrier doors, that the north barrier door to the East Valve Trench Area (in the Unit 1 Primary Auxiliary Building) was closed but not locked as required. Radiation levels in certain areas of the East Valve Trench Area exceeded 1000 mr/hr. Unit 1 Technical Specification 6.12.2 requires locked doors be provided to areas where the radiation intensity was greater than 1000 mr/hr. The area was immediately searched and no individuals were found in the area.

The licensee determined a welded latching mechanism which had been used in the past to lock the door with a padlock had flipped back around the striker plate area of the currently used door plate locking mechanism. This prevented the door from locking. As an immediate corrective action, the welded latching mechanism was secured to prevent further interference with the door plate locking mechanism and was subsequently removed from the door.

The licensee conducted an extensive investigation of the incident. As a conservative measure, the licensee locked shut all barrier doors to areas where radiation levels exceeded 100 mr/hr and checked that these barrier doors were locked shut every eight hour shift. Interviews with radiation protection (RP) personnel who perform the barrier door check, revealed that the barrier door to the East Valve Trench was verified locked shut nine hours prior to discovery that the door was not locked. The RP technicians who had checked out keys that would have gained access to the above area were interviewed, but it could not be determined if anyone had entered the area. Radiation exposure records were examined of all personnel who could have entered the area but no unaccounted exposures were found. The area required respiratory protection but examination of the respiratory sign-out log indicated no personnel had checked out a respirator to be used in that area.

As additional corrective measures, the licensee increased the check of locked barrier doors to twice a shift. RP technicians qualified to sign out keys to areas of greater than 1000 mr/hr were counselled to perform a hands on check of the closed radiation barrier door prior to exiting the area.

Although the radiation barrier door was not locked as required, it did not appear that an unauthorized entry into the East Valve Trench was made. The inspector concluded that the incident was of minor safety significance. The incident was reported to the NRC via Unit 1 LER 89-14-00 as required. The licensee's corrective actions and investigation of the incident were thorough and timely. In addition, there were no past similar occurrences identified. Therefore, the failure to meet the requirements of Technical Specification 6.12.2 is not being cited because the criteria specified in Section V. G of the Enforcement Policy were satisfied. (Non-cited Violation NCV 50-334/89-23-02) (Closed).

8. Unit 1 Inadvertent Challenge to Safety Systems While Shutdown

On December 13, 1989, while Unit 1 was in Cold Shutdown (Mode 5), Train A reactor trip and safety injection signal were actuated. The Train A emergency diesel generator automatically started and the Train A containment isolation valves repositioned as designed. No injection into the reactor coolant system occurred.

At the time of the event, Operating Surveillance Test (OST) 1.36.4 "Diesel Generator No. 2 Automatic Test" was in progress. As part of the OST, the Train A of the Solid State Protection System (SSPS) was placed into test in accordance with Operating Manual (OM) 1.1.4W "SSPS Alignments." The placement of SSPS Train A into test defeated the blocks associated with the pressurizer low pressure safety injection signal and the steam line low pressure safety injection signal.

The initial valve lineup at the OST also required that the Main Feedwater Regulating Valves be open. The control room operators determined that the valves could not be opened if the Train A reactor trip breaker was open and the breaker could not be shut if SSPS Train A was in test. Control room operators decided to restore SSPS to service in order to manipulate the reactor trip breakers and subsequently open the Main Feedwater Regulating Valves. A licensed operator was directed to return SSPS Train A to service but specific guidance how to perform the task was not given.

When returning a SSPS train to service, OM 1.1 4W required that protection signals be inhibited until the blocks for the pressurizer low pressure safety injection signal and the steam line low pressure safety injection signal were reinstated. The licensed operator dispatched to return SSPS

Train A to service failed to inhibit the protection signals before placing the SSPS Train A mode selector switch to "Operate." This resulted in the generation of a Train A safety injection and reactor trip signal. The Train A emergency diesel started and Train A containment isolation valves repositioned as required. The control room operator responded to the event as required. Other Train A safety equipment was defeated as part of the OST and no injection into the Reactor Coolant System occurred.

Several weaknesses contributed to the event. The OST did not have guidance on how to open the Main Feedwater Regulation Valves with the reactor trip breaker open. The guidance given to the operator assigned to return the SSPS train to service by shift supervision was not specific as to the procedure to be used. The failure of the operator to follow OM 1.1.4W when returning the SSPS train to service is a violation (50-334/89-23-01).

9. Unit 1 Feedwater Isolations

On two occasions in December 1989, the Unit 1 feedwater system automatically isolated (Engineered Safety Feature) on high indicated steam generator level. The two events were interrelated as to the causes and demonstrated an apparent weakness in the control of corrective maintenance activities.

During the seventh refueling outage, a number of the narrow range steam generator (SG) level transmitters were replaced. As part of the clearance for this effort, both the instrument line root valves and the instrument block isolation valves had been tagged shut. The instrument line root valves were Kerotest 3/4 inch packless metal disk globe valves which utilized spring forces to open the valve disk when the valve was opened. The Kerotest valves had been installed as part of a modification to reduce personnel exposures. The original root valves required occasional valve stem repacking in areas of relatively high radiation levels. After the level transmitters were replaced, the clearances were removed and isolation valves were returned to normal system alignment (open).

On December 15, 1989, while in Hot Shutdown (Mode 4), approximately 15 minutes after control room operators had filled the 1B SG to approximately 85% by wide range indication (60% by narrow range), two of the three narrow range channels drifted above 75%. This resulted in a Feedwater Isolation (FWI). The wide range SG level remained stable. The two narrow range level channels were subsequently declared inoperable.

The licensee's corrective activities were directed into two areas. Calibration checks of the 1B SG narrow range level transmitters were to be performed. In addition, steps were to be taken to verify that the 3/4 inch Kerotest root valves were open. These steps included shutting the root valves, depressurizing the downstream side of the valve, and then reopening the valves; thus, the pressure surge would fully open the valve. If this failed, the valves would be mechanically agitated with a brass hammer to unstick the closed valve disk.

On December 16, 1989, another FWI occurred while trouble shooting the above event. A calibration check of one channel was in progress which resulted in an above 75% level signal from that channel. At that same time, technicians inside the containment mechanically agitated the Kerotest root valve associated with another 1B SG level transmitter. The root valve which was stuck closed, opened, causing the level signal to spike high. This in turn resulted in a FWI. The cause of the event was that the technicians were permitted to work on two level channels at the same time and indicated a weakness in the control of maintenance activities.

The calibration checks of the two level channels indicated both narrow range channels were properly calibrated. The other Kerotest root valve was also mechanically agitated and the level signal returned to its proper level. The licensee verified proper narrow range level indication by raising and lowering 1B SG water level several times. No further problems were observed. In addition, the licensee installed signal recorders on all SG level transmitters to monitor the level channels during the planned heat up into Hot Standby (Mode 3). All the channels properly tracked during the heat up.

The inspector questioned whether other Kerotest root valves had been shut during the outage and what other instrumentation may not be operable. The licensee stated that 3/4 inch Kerotest root valves were also utilized for Main Steam flow and SG pressure instrumentation. The licensee performed an analysis on data obtained following a reactor trip from 29% power (see Section 4.3.5) and determined that all the above instrumentation responded properly.

The licensee's subsequent review found that for the 3/4 inch Kerotest valves, the spring which repositions the valve disk when the valve handle had been moved to the open position, did not have enough force to adequately ensure that the valve disk repositioned. The licensee stated that guidance would be given to personnel preparing clearances directing that the 3/4 inch Kerotest valves not be shut unless absolutely necessary.

The licensee was evaluating various corrective actions to be taken if the 3/4 in. Kerotest valves are shut in the future. The inspector had no further questions.

10. Unit 2 Lines Freezing Due to Cold Weather

At various times in the month of December, some Refueling Water Storage Tank (RWST) level sensing lines froze. During December, there were several days of severe cold weather (less than 0°). On December 28, 1989, the licensee declared one of the four RWST level indicators inoperable due to freezing in a portion of its associated sensing line. These transmitters provided the signal for the automatic transfer of the ECCS suctions to the containment sumps. The sensing line was promptly thawed using a heat gun and the channel was returned to service. Later, a sensing line for a different set of RWST level transmitters froze. This instrument (100A) provided a signal (one of two) to transfer the discharge of the Chemical Addition Pumps from the suction of the Low Head Injection Pumps to the containment sump. This line was subsequently thawed. Shortly afterwards, the sensing line of the other channel (100B) froze and had to be thawed.

To prevent further problems, the licensee installed temporary heaters and erected tents around the RWST sensing lines. No further problems were identified. Investigation by the licensee determined that the lines were freezing in the area around the instrument line isolation valves and transmitter vent plugs. The licensee had modified and upgraded the RWST heat tracing and insulation after experiencing line freezing problems in January 1988 (see IR 50-334/88-01; 50-412/88-01). Insulation had not been provided for the isolation valve handles and transmitter vent plugs to allow for easy access and operation. The licensee stated that a modification was being planned to further upgrade the insulation/heat tracing to prevent recurrence.

The inspector reviewed the licensee preparations for cold weather. All heating and heat trace systems were verified to be operable prior to the onset of cold weather. The inspector had no further questions.

11. 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 89-011-00 Pressurizer Rupture Restraints Outside the Design Basis.

LER 89-014-00 Barricaded but Unlocked High Radiation Door.

Unit 2:

LER 89-026-00 Inadvertent Steam Generator Blowdown Isolation - Engineered Safety Features Actuation.

LER 89-027-00 ESF Actuation - Automatic Transfer of Seal Water Supply.

The above LERS were reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. Generally, the LERs were found to be of high quality with good documentation of event analyses, root cause determinations and corrective actions.

The inspector identified some errors in Unit 1 LER 89-014-00. The description of Technical Specification (TS) 6.12.1 was incorrect. The TS required that barrier doors to high-high radiation areas (greater than 1000 mrem/hr) be locked, however, the LER describes the requirement as applicable to high radiation areas (greater than 100 mrem/hr but less than 1000 mrem/hr) giving the reader the false impression that the radiation levels in the area that was found unlocked was less than 1000 mrem/hr when, infact, the radiation levels were greater than 1000 mrem/hr. In addition, the date of the event in the Abstract Section and Text was incorrect. The date of the event was correctly given in Block 5, "Event Date." The licensee indicated a revision to the LER would be issued. The inspector had no further questions.

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 January 12, 1989.