U. S. NUCLEAR REGULATORY COMMISSION
REGION 1

Report Nos.	50-334/90-20 50-412/90-20	License:	DPR-66 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: September 8 - October 19, 1990

Inspectors: J. E. Beall, Senior Resident Inspector
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Approved by: William H. Ruland 11/16/90
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Reactor Projects Section No. 4B

Inspection Summary

This inspection report documents routine and reactive inspections during day and backshift hours of station activities including: plant operations; radiological protection; surveillance and maintenance; emergency preparedness; security; engineering and technical support; and safety assessment/quality verification.

Results

One Unresolved Item was identified concerning potential weaknesses in the engineering review of a Unit 2 Reactor Coolant System loop "C" pressure event (see Detail 7.1). Several Engineered Safety Feature actuations were reviewed. Operator responses to the events were good (see Detail 2.3). Emergency Squad actions in response to a serious personnel injury were found to be outstanding (see Detail 2.3.2). Improvements in the licensee Maintenance Department's root cause analysis and Post Maintenance Test Program were noted (see Detail 4.4). Licensee activities associated with reduced Recirculation Spray system heat exchanger River Water flow were reviewed where a good safety perspective was demonstrated (see Detail 7.2). Four previous NRC open items were reviewed and closed.

EXECUTIVE SUMMARY FOR INSPECTION REPORT

50-334/90-20 & 50-412/90-20

Plant Operations Several Engineered Safety Feature actuations were reviewed. These included the full closure of a Unit 1 main steam trip valve resulting in a forced plant shutdown, and three unrelated Unit 2 containment purge duct automatic isolations. The inspector determined that all these events were of low safety significance and that operator response during the event was good. The inspector found the response of the licensee's Emergency Squad following a worker's fall was outstanding and instrumental 'n saving the injured worker's life. The inspector referred the event to OSHA. Housekeeping at both units was good despite the high level of work activitits associated with the Unit 2 refueling outage.

Radiological Protection Routine review of the areı identified no noteworthy observations.

Surveillance and Maintenance Changes in the maintenance department's requirements and post maintenance test program were reviewed. The initiatives were found to be notable improvements. Type C testing was properly conducted using conservative test methodology. Several maintenance activities were observed in conjunction with the Unit 2 outage and no notable observations were identified.

Emergency Preparedness Routine review of this area identified no noteworthy observations.

Security Routine review of this area identified no noteworthy observations.

Engineering and Technical Support An Unresolved Item was identified concerning potential weaknesses in the engineering review of a Unit 2 loop pressurization event. Strong support from the licensee's engineering and licensing departments was demonstrated in resolving Unit 1 Recirculation Spray system heat exchanger cooling water flow issues. A temporary waiver of compliance was issued by NRR after the licensee resolved the safety issues.

Safety Assessment/Quality Verification

A good safety perspective was demonstrated in the decision to pursue investigation of the initially adequate but degrading river water test results.

TABLE OF CONTENTS

DETAILS

1. Summary of Facility Activities

At the beginning of the inspection period, Unit 1 was operating at full power and Unit 2 was in Cold Shutdown (Mode 5) for the second refueling outage. Unit 1 remained at full power until October 6 when the unit was shut down following the closure of a main steam trip valve during surveillance testing (see Detail 2.3.3). Unit 1 returned to power operation on October 10 and remained at full power for the remainder of the period.

Unit 2 defueling operations commenced on Septembe 12, and on September 22 core off-load was completed. Core reload began on October 10 and Mode 5 was entered at the completion of refueling activities on October 17. Unit 2 remained in Mode 5 for the remainder of the period.

2. Plant Operations

2.1 Operational Safety Verification

The inspectors observed plant operation and verified that the plant was operated safely and in accordance with licensee procedures and regulatory requirements. Regular tours were conducted in the following plant areas:

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

During the course of the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration and plant conditions. The inspector verified adherence to approved procedures for observed activities. Shift turnovers were witnessed and staffing requirements confirmed. The inspectors found that control room access was properly controlled and a professional atmosphere was maintained. Inspector comments or questions resulting from these reviews were resolved by licensee personnel.

Control room instrument and plant computer indications were observed for correlation between channels and for conformance with Technical Specification (TS) requirements. Operability of engineered safety features, other safety related systems and onsite and offsite power sources were verified. The inspectors observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Compliance with TS and implementation of appropriate action statements for equipment out of service was inspected. Logs and records were reviewed to determine if entries were accurate and identified equipment status or deficiencies. These records included operating logs, turnover sheets, system safety tags, and the jumper and lifted lead book. The inspector also examined the condition of various fire protection, meteorological, and seismic monitoring systems.

Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards. The inspector conducted detailed walkdowns of accessible areas, including the Unit 2 containment building. Housekeeping at both units was good despite the high level of work activities associated with the Unit 2 refueling outage.

2.2 Engineered Safety Features System Walkdown

The operability of selected engineered safety feature 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 included the Emergency Diesel Generators, Safety Injection, Auxiliary Feed and Recirculation Spray systems. No concerns were identified.

2.3 Event Follow-up

During the inspection period, the inspectors provided onsite coverage and followup of unplanned events. Plant parameters, performance of safety systems, and licensee actions were reviewed. The inspectors confirmed that the required notifications were made to NRC. The following events were reviewed:

2.3.1 Unit 2 Containment Purge Duct Isolation

Between September 13 and 16, 1990, three automatic isolations of the Unit 2 containment purge ducts occurred. Unit 2 was in Cold Shutdown (Mode 5) during each event. The causes of the isolations were unrelated. The isolations were Engineered Safety Features actuations and all were reported to the NRC as required.

There are two containment purge ducts, one supply and one exhaust. Each duct has two motor operated isolation dampers with one damper inside containment and the other outside. There are two Unit 2 radiation monitors which generate isolation signals to the containment purge line isolation dampers. HVC*RQ104A provides the isolation signal for the two outside containment purge isolation dampers and HVC*RQ104B provides the isolation signal to the two inside containment isolation dampers. Both radiation monitors sample the containment exhaust duct.

The first containment purge isolation occurred on September 13 during a source calibration of 2HVR*104B. A communication error by technicians performing the calibration resulted in an artificial high alarm condition and the inside dampers isolated. The artificial high signal was subsequently cleared, the source calibration was completed, and containment purge was re-established. To prevent recurrence, the maintenance surveillance procedures for the radiation monitors were revised to require that the automatic high radiation actuation signals be disabled during the calibration procedure. The inspector determined that the event was of minor significance and that the licensee's corrective actions should be effective to prevent recurrence.

The second containment purge isolation occurred on September 15. While filling the reactor cavity for refueling, radiation monitor 2HVR*104B alarmed and the inboard isolation dampers automatically shut. At the time of the isolation, the control operator observed no significant increase in activity on 2HVR*104A. The operators responded to the isolation in accordance with procedures.

The licensee determined that the detector associated with 2HVR*104B had become contaminated when containment airborne activity increased due to water turbulence during the reactor cavity fill. The isolation setpoint for the radiation monitor was set to three times background. The actual activity increased only 17 percent during cavity fill as independently verified by measured air samples taken in the containment. As a precautionary measure, personnel were evacuated from the containment refuel floor and checked for contamination. No personnel contamination was identified. The affected detector was cleaned and containment purge was reestablished.

Due to the containment purge isolation, a differential pressure was established between the containment and the fuel handling building. The fuel transfer canal was open and this differential pressure caused the water level in the spent fuel pool to rise. This, in combination with higher than normal spent fuel pool/reactor water cavity water level, caused the spent fuel pool to overflow. The licensee's actions regarding the resultant radioactive spill were reviewed in report 50-334/90-19; 50-412/90-19. Once identified, control room operators promptly took action to lower reactor cavity water level.

The licensee's response to the event was good. The actions taken were prompt and conservative. The inspector determined the event to be of low safety significance.

The third containment purge isolation occurred on September 16, when the reactor vessel upper internals were being moved out of the vessel to the reactor cavity. During this movement, 2HVR*104A alarmed high and the containment purge outboard isolation dampers closed. The cause of the isolation was an increase in background radiation resulting from direct "shine" from the upper internals. The radiation monitor was located in a direct line of sight from the internals. The operators responded to the event in accordance with procedures. No abnormal airborne radioactivity levels were identified. The inspector found that the licensee took all appropriate actions and the event was of minor safety significance.

2.3.2 Serious Injury Following Fall

On September 26, 1990, a carpenter fell about 60 feet in the Unit 2 cooling tower. The worker descended a ladder onto a suspended scaffold inside a deep shaft to modify the scaffold in support of a work activity. The worker removed one plank from the scaffold and fell to the bottom of the shaft while trying to ascend the ladder off the scaffold. One medically trained operator was lowered down the shaft (about 80 feet deep) while others entered an underground channel, traversed over 100 feet of tunnel, and evacuated the injured to an ambulance driven into the empty tower basin. The worker was then flown by helicopter to a Pittsburgh hospital and admitted in critical condition.

The inspector conducted a preliminary review of the event and found the response of the licensee's Emergency Squad (plant operators) to be outstanding and instrumental in saving the injured worker's life. The inspector forwarded details of the accident to the Occupational Safety and Health Administration for possible followup.

2.3.3 Unit 1 Unplanned Shutdown

On October 6, 1990, Unit 1 was shut down following the full closure of a main steam trip valve during partial stroke surveillance testing of the valve. Just prior to the event, reactor power had been reduced from 100 percent to 27 percent to allow for the repair of a main feedwater regulating valve. While at this reduced power, surveillance testing on the main steam trip valves, as required by Technical Specification 3.7.1.5, was performed.

The main steam trip valves are standard swing check valves. However, the valves are installed counter to normal flow. The valve disc is normally held out of the steam flow path by two air operators. To close the valve, air is vented from the operator via two redundant solenoid valves causing the disc to drop into the steam flow which rapidly closes the valve.

A third solenoid is provided for partial stroking of the valve. The purpose of the partial stroke surveillance test was to verify valve movement. A local test push button energizes the third solenoid to vent air until the trip valve strokes three degrees. A valve limit switch then de-energizes the solenoid to return the trip valve to its full open position.

While performing partial stroke testing of the "B" main steam trip valve, the valve unexpectedly stroked fully shut. The resulting transient did not cause a reactor trip or other Engineered Safety Feature actuation. As required by Unit 1 procedures, control room operators commenced an emergency shutdown and entered Hot Standby (Mode 3) approximately 30 minutes after the closure of the valve.

Following the shutdown, the licensee conducted a detailed investigation of the event over the course of three days. The valve was both fully and partially stroked three times and the problem could not be repeated. The exact cause of the event could not be determined. On October 10, Unit 1 returned to power operation.

The operator's response to the event was appropriate. Licensee root cause evaluation was still in progress at the end of the inspection period and will be reviewed during routine inspection activities. The inspector found that the event was of minor safety significance. The closure took place at 27 percent power. Closure at 100 percent power is a transient which according to the Nuclear Steam Supply System vendor, is bounded by the Loss of External Electrical Load or Turbine Trip transient analyzed in FSAR Section 14.1.7.

3. 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.

There were no notable observations.

4. Maintenance and Surveillance

4.1. Maintenance Observation

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 899387	Steam Leak Repair Feed Header Check Valve 2FW5-30
MWR 899385	Steam Leak Repair Feed Header Check Valve 2FWS-29
MWR 908278	Change Out Rotating Elements of Motor Driven Auxiliary Feedwater Pump 2FWS*P23B
MWR 908683	Inspect and Repair Seal - 2FWE-44A
1/2-RCP-51	Calibration of ITE Phase Sequence and UV Relay
2TOP-90-20	Vendor Inspection and Adjustment of 2EGS*EG2-1
2TOP-90-20	Vendor Inspection and Adjustment of 2EGS*EG2-2
2TOP-90-20	Recirculation Spray Heat Exchanger Leak Test

There were no notable observations.

4.2 Surveillance Observation

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:

Unit 1

OST 1.24.3	Motor Driven Auxiliary Feed Pump Test (1FW-P-3B)
OST 1.30.2	Reactor Plant River Water Pump Test

Unit 2

OST 2.36.2	Emergency Diesel Generator (EGS*EG-2) Monthly Test

There were no notable observations.

4.3 Type C Leakage Testing

The inspector conducted a review of the licensee's compliance with Technical Specification 3.6.1.2.b. That TS requires that the leakage rate for all containment penetrations subject to Type B and C tests per 10 CFR 50, Appendix J, be maintained less than 0.60 La (where La is equal to maximum allowable leakage rate at the calculated peak containment internal pressure during a design base accident). The licensee verifies compliance with this requirement, in part, by completing test procedure 2-BVT-01.47.05 "Containment Type C Leak Test." Type B testing and testing of electrical penetrations are conducted using other test procedures.

The inspector verified the following items through a review of the Type C test for mechanical penetrations, interviews with test personnel, and direct observation:

-- Mechanical penetrations were tested at 46 psig as opposed to the minimum required pressure of 44.7 psig to allow for gauge inaccuracies.

-- A sample of test points was reviewed to demonstrate that test pressure is applied in the direction that containment isolation would be accomplished.

-- The test procedure specifies that the initial testing be conducted without preliminary exercising or adjustments. A number of valves worked during the outage were tested "as found" and again after maintenance for "as left" data.

-- Test procedures were current. Test equipment had been calibrated weekly. Operations personnel performed plant system manipulations and test personnel operated test equipment.

-- Time was allowed for leak rate stabilization following pressurization. Data was taken six times at one minute intervals to document a stable or decreasing leak rate. The leak rates were determined by converting the highest observed data point to absolute (standard cubic feet per day) units. The leak rates for each penetration were then summed to determine the overall leakage rate for compliance with the technical specification. A measurement error was also determined for each penetration, as required.

The inspector found the observed Type C tests were properly conducted using conservative test me hodology.

4.4 Site Maintenance Program Improvements

The inspector reviewed two licensee initiatives to improve maintenance performance. The licensee's Maintenance Department has adopted a formal failure analysis process to be used by maintenance engineers to determine root cause for component failures or other maintenance related events. By procedure, all completed high priority corrective maintenance (priority 1 or 2) were required to have the formal root cause determination performed. Additionally, any other corrective maintenance for which the root cause was not readily obvious, the maintenance engineers were required to use the formal root cause analysis process. The inspector reviewed several selected completed maintenance work requests to determine the quality of the root cause analysis performed. The inspector found that a formal root cause determination was performed as required. The analyses were thorough and detailed.

The licensee has also made improvements to the post maintenance test program. Nuclear Group Administrative Manual, chapter 7.5, "The Maintenance Work Request," had been revised to include additional post maintenance test requirements. A Post Maintenance Test (PMT) sheet was required to be completed by licensee maintenance engineers delineating any required PMTs. The sheets contained common PMTs for the type of component undergoing maintenance and contained an area were specific other PMTs could be included. The inspector reviewed several selected PMT sheets and found that the proposed post maintenance tests appeared to adequately ensure that the maintenance was correctly performed. The inspector reviewed a licensee evaluation of the effectiveness of the revised PMT program. The study found that the program was successful in identifying all maintenance requiring rework in a sample of fifty maintenance activities (four percent required rework).

The inspector found that the above maintenance program improvements were effective and well implemented.

5. Emergency Preparedness

The response of the licensee's Emergency Squad to a personnel injury (Section 2.3.2) was found to be outstanding. There were no other notable observations.

6. Security

Implementation of the Physical Security Plan was observed in various plant areas as follows:

- -- 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 was controlled 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 written procedures were available; and
- -- Adequate illumination was maintained.

There were no noteworthy observations.

7. Engineering and Technical Support

7.1 Potential Overpressurization of Unit 2 RCS, Loop C

7.1.1 Event Chronology

On September 7-8, 1990, licensed operators identified that a potential overpressurization event had occurred involving the C loop of the Unit 2 RCS. A procedural oversight allowed seal injection (about 6 gpm) into the isolated C loop from a running high pressure charging pump. The event was identified after safety injection tank level was noted to have risen about 50% in indicated level and about 70 psi. No loop pressure data was available but the safety injection tank maximum pressure was about 580 psig. The temperature of the C loop was 109 F hot leg and 99 F cold leg. Operators took corrective action and pressure was noted to be decreasing about 35 minutes later.

7.1.2 Regulatory Background

Technical Specifications (TS) require that RCS pressure and temperature remain within certain limits. These limits are presented in TS Figures 3.4-2 and 3. If a limit is exceeded, the licensee is required to "restore the temperature and/or pressure to within the limit within 30 minutes [and] perform an analysis to determine the effects of the out-of-limit condition on the fracture toughness properties of the "Reactor Coolant System." The limiting RCS component is the reactor vessel due to its thickness and the gradually embrittling effect of long term exposure to fast neutrons throughout plant life. These factors are discussed in 10 CFR 50, Appendix G and in the Beaver Valley TS Bases 3/4.4.9. Both documents concentrate on the reactor vessel and the effects on the vessel wall during RCS heatup and cooldown. Neither specifically addresses pressure within an isolated RCS loop but the Appendix G Introduction begins as follows:

This appendix specifies fracture toughness requirements for ferritic materials of pressure-retaining components of the reactor coolant pressure boundary . . . .

The Beaver Valley RCS piping and valve bodies are not made of ferritic materials but rather austenitic stainless steel. The Beaver Valley Technical Specifications specifically provide an additional limit for the steam generators by requiring that steam generator temperature be greater than 70 F before exceeding 200 psig on either the primary or the secondary side. One effect of this requirement is to place limits on steam generator air pressure leak tests and nitrogen gas blankets using positive pressure when the RCS is depressurized below 70 F. The TS curves do not allow RCS pressure to be above atmospheric below 70 F.

7.1.3 Review of Fracture Toughness Effects Analysis

The Nuclear Engineering Department was tasked to complete the analysis required by TS 3.4.9.1 following the event. The analysis (Engineering Memorandum 76372) was completed on September 14, 1990, and transmitted to the plant manager. The inspector reviewed Engineering Memorandum 76372 and had certain concerns.

The Engineering Memorandum (EM) contained little analysis and argued that TS 3.4.9.1 did not apply because the 10 CFR 50, Appendix G limiting component (the reactor vessel) was not affected. It is the inspector's opinion that the EM is not entirely correct because TS 3.4.9.1 applies the specific limits to the entire Reactor Coolant System and not just the reactor vessel. This is not a safety issue because the RCS piping receives little fast neutron fluence and is made out of austenitic (vice ferritic) materials. In the absence of specific limits for an isolated RCS loop, however, the limits of TS 3.4.9.1 would appear to apply.

The EM concluded with the following statement:

Evaluation of the [RCS] loop stop valves indicate the isolated loop pressures did not exceed 600 psig and most likely never exceeded what [safety injection tank] pressures indicated in the [control room].

The inspector questioned the author of the EM concerning the evaluation. The relief capacity inherent in the double-disk design of the RCS loop stop valves had been determined to be adequate for the 6 gpm seal injection flow. The pressure needed to initially move the valve disk off its seat (static friction) did not appear to have been determined. The inspector also questioned how flow could have occurred without a differential pressure between the RCS loop and the safety injection tank.

No additional information was provided to the inspector by the end of the inspection period.

7.1.4 Summary

An over-pressurization event occurred on September 7-8, 1990, involving the austenitic stainless steel portion of the RCS pressure boundary while in Cold Shutdown (Mode 5). Concerning this event:

1) The pressure limits of TS 3.4.9.1 (Figure 3.4-2 and 3) were apparently exceeded. The condition duration also exceeded the 30 minute restoration limit. In mitigation, there was no impact on safety because the condition affected only one isolated RCS loop and not the reactor vessel.

2) The differences in materials (ferritic vs. austenitic) indicate that TS 3.4.9.1 should be reviewed for possible revision to address limits applicable specifically to isolated RCS loops. The lack of specificity in the Technical Specifications contributed to the licensee's conclusion that TS 3.4.9.1 did not apply, and therefore that no 10 CFR 50.72 or 50.73 report was required.

This item is Unresolved pending the licensee's resolution of the TS question. (50-412/90-01).

7.2 Reduced Recirculation Spray Heat Exchanger River Water Flow

During conduct of a quarterly surveillance test on October 3, 1990, the licensee noted an unexpected drop in River Water system flows to the Unit 1 "A" train Recirculation Spray heat exchangers (1A and 1C). The licensee conservatively elected to conduct additional testing although the observed flows were sufficient for the surveillence test. Further flow reductions were observed and the most affected heat exchanger (1C) was declared inoperable (TS 3.6.2.2 and 4.6.2.2.e.3).

The design basis river water flow is based on a LOCA occurring with river water temperatures approaching 90 F. The river water flow would remove the decay heat (via the Recirculation Spray heat exchangers) in the Containment following the LOCA. The analysis conservatively assumed that the accident would occur with elevated ambient temperatures. The actual river water temperatures during the inspection were above 60 F and generally decreasing.

The licensee performed an analysis assuming a reduced river water temperature of 75 F and demonstrated that the required flow rate for design basis heat removal could be reduced (6000 gpm vs. the original 8000 gpm). The analysis concluded that the Recirculation Spray heat exchangers could still perform their design function and could be considered operable with the current river water temperature. The inspector reviewed the analyses in conjunction with NRR and identified no deficiencies.

The licensee also conducted additional testing and an examination of the river water portion of the affected heat exchanger. The licensee found no clear cause of the reduced flow but did confirm that no damage or large foreign material was involved.

On the basis of the analyses, testing and examination of the river water system, the licensee requested on October 18, and received on October 19, a Temporary Waiver of Compliance from the applicable section of the TS. The licensee submitted a TS amendment on October 25 for NRC review which would allow continued operation until the scheduled April 1991 refueling outage. The revised sections generally place greater restrictions on maximum river water temperature and containment pressure while allowing a reduction in river water system flow.

In summary, the licensee showed good safety perspective in electing to pursue the initially adequate but degrading river water system performance. Licensee investigatory activities were found to be thorough and comprehensive. Engineering support was prompt and extensive and enabled the licensee to conclude, and the NRC to concur, that the plant could continue to operate safely within its design bases.

8. Safety Assessment and Quality Verification

8.1 Review of Written Reports

The inspector reviewed LERs and other written reports to the NRC Region I Office to verify that the details of the events 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 90-013-00	Control Room Emergency Breathing Air Pressurization System Actuation - ESF Activation
LER 90-014-00	ESF Actuation - Steam Generator Blowdown Isolation

Unit 2:

LER 90-009-00	ESF Actuation - Letdown Isolation on Loss of Containment Instrument Air Pressure
LER 90-010-00	Letdown Isolation Due to Low Pressurizer Water Level
LER 90-011-00	ESF Actuation - Containment Purge Isolation Due to High Radiation Signal

LER 90-012-00 ESF Actuation - Containment Purge Isolation Due to Improper Radiation Monitor Restoration

LER 90-013-00 ESF Actuation - Containment Purge Isolation During Reactor Cavity Fill

LER 90-014-00 ESF Actuation - Containment Purge Isolation During Upper Internals Lift

LER 90-015-00 Containment Liner Test Channel Vents Found Unplugged

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 had good documentation of event analyses, root cause determinations, and corrective actions. The inspector noted that one LER (Unit 2 90-013) did not discuss all the results of the event. The spent fuel pool overflow discussed earlier (Section 2.3.1) and the resultant contamination were not mentioned.

8.2 Licensee Safety Perspective

As discussed in Section 7.2, the licensee showed good safety perspective in electing to pursue the initially adequate but degrading river water system performance. Licensee investigatory activities were found to be thorough and comprehensive.

9. 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.

9.1 (Closed) Violation 50-412/88-18-01: Failure to comply with Site Administrative Procedure (SAP) 17, "Reporting of Defects and Noncompliances." This item had been previously reviewed in Inspection Report 50-334/89-23, 50/412/89-22. The item remained open because the inspector found that in one instance a potential defect was not promptly reported to the Nuclear Safety Department as required by SAP 17 and that there was conflicting guidance between Nuclear Engineering Department Standard (ES)-A-1005, "Identification and Evaluation of 10 CFR 21 Concerns" and SAP 17. The guidance in the ES gave responsibility for evaluating and tracking potential 10 CFR 21 concerns to the manager of the Nuclear Engineering Department vice the manager of the Nuclear Safety Department as required by SAP 17.

The Nuclear Engineering Department ES has subsequently been revised to require that all identified deviations, defects or other substantial safety hazards be promptly reported to the manager of the Nuclear Safety Department in conformance with the site administrative procedure. In addition, all Nuclear Engineering Department personnel have been advised that all potential 10 CFR 21 concerns must be promptly reported in writing to the Nuclear Safety Department.

The inspector found no instances where potential defects were not promptly reported to the Nuclear Safety Department. The inspector had no further questions.

9.2 (Closed) Violation (50-334/89-22-01): Failure to update control room status boards as required by Site Administrative Procedure (SAP) 41, "Clearance Procedure." In November 1989, the failure to update the Unit 1 control room status boards to reflect a clearance on the Reactor Coolant System (RCS) resulted in control room operators failing to recognize that a required channel of overpressure protection was inoperable during a subsequent RCS pressurization. This item was reviewed in Inspection Report 50-334/90-12, 50-412/90-12. At that time, the inspector had identified two clearance tags posted on plant equipment that were not reflected on the Unit 1 control room status board prints.

The inspector reviewed the licensee's corrective actions to prevent recurrence. In addition to counselling the individuals involved with the above event, the licensee has made changes to strengthen the status board program. Special Operating Order 1-90-005 was issued on August 14, 1990, that required that all valve manipulations be recorded on a valve status control tracking form. The only exception was valve manipulations directed by procedures which returned the valves to its normal system alignment by the end of each shift. The shift foreman was assigned responsibility for ensuring that all the status board prints were correctly updated at the end of the shift.

The inspector reviewed the Unit 1 control status boards to determine if clearances and other valve manipulations were properly reflected on the status board prints. No deficiencies were identified. The inspector had no further questions.

9.3 (Closed) Unresolved Item (50-334/89-12-02, 50-412/89-13-02): Licensee to correct program to control position of instrument root valves in containment. This item involved a Unit 2 Reactor Coolant System (RCS) leak from an instrument line tap. The instrument line root valve was not shut and the end fitting had become dislodged. The licensee conducted a detailed containment walkdown and corrected several similar deficiencies. The licensee revised procedures for both Unit 1 and Unit 2 to require position verification of these instrumentation valves in the RCS and other high energy systems inside the containments prior to startup from an extended outage. The inspector reviewed the revised procedures and had no further questions.

9.4 (Closed) Violation (50-334/88-22-03): Cable separation violations, indicative of a programmatic weakness in the QA Program. The inspector confirmed that the examples cited had been corrected and that programmatic improvements had been made. Additional corrective actions will be reviewed during follow-up of Violation 50-334/89-12-01.

10. Exit Meeting

10.1 Preliminary Inspection Findings Exit

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 October 29, 1990.

10.2 Attendance at Exit Meetings Conducted by Region-Based Inspectors

Dates	Subject	Inspection Report No.	Reporting Inspector
9/17/90 to 9/21/90	Radiological Controls	50-334/90-19; 50-412/90-19	O'Connell
9/16/90 to 9/18/90	Fitness for Duty	50-334/90-21; 50-412/90-21	King