U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-387/87-06; 50-388/87-06

Docket Nos. 50-387; 50-388

License Nos. NPF-14; NPF-22

Licensee: Pennsylvania Power and Light Company

2 North Ninth Street

Allentown, Pennsylvania 18101

Facility Name: Susquehanna Steam Electric Station

Inspection At: Salem Township, Pennsylvania

Inspection Conducted: February 18, 1987 - March 31, 1987

Inspectors: L. R. Plisco, Senior Resident Inspector

J. R. Stair, Resident Inspector

K. A. Manoly, Lead Reactor Engineer

Approved By: J. J. Wiggins, Chief, Reactor Projects Section 1B, DRP — 4/14/87 Date

Inspection Summary:

Areas Inspected: Routine resident inspection of plant operations, radiation protection, physical security, plant events, previous inspection findings, surveillance, maintenance, and Information Notice Followup.

Results: Lack of control of NCR Hold Tags was identified during a station tour (Detail 2.2); minor deficiencies were noted in a walkdown of the Unit 1 LPCI System (Detail 2.3); a maintenance technician was injured during a valve packing repair (Detail 3.3); control rod position to 65 individual rods was lost three times on Unit 2 (Detail 3.4); an unauthorized issuance of a respirator (Detail 3.5); four potentially defective motor operators were identified in response to IEN 87-08 (Detail 6.0); and the licensee identified the use of styrofoam in the Reactor Buildings (Detail 7.0).

No violations were identified.

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DETAILS

1.0 Followup on Previous Inspection Findings

1.1 (Closed) Unresolved Item (387/83-25-02; 388/83-24-01): Temperature and Pressure Deficiencies Identified in Design Specification M-199; RHR Spray Header Reanalysis

This item was related to the reanalysis and evaluation of the RHR drywell spray header for higher design temperature which was previously reviewed in NRC inspection reports 387/84-08; 388/84-18 and 388/84-22. The concerns remaining from the last NRC inspection included: (1) overstress of trunnion welds for supports GBB-118-H5 and GBB-118-H6 on piping spray header "A"; and, (2) justification for acceptance of the piping and supports for header "B" (line no. GBB-113) in Unit 1 and headers "A" and "B" (line no. GBB-218) in Unit 2 as a result of the increased piping design temperatures.

The licensee's response included reevaluation of the welds between the trunnion and the process pipe using actual as-built weld configurations (sizes and lengths) around the trunnion circumference. The stresses were determined to be below the allowable code limit of 18 ksi.

The response also indicated that the radial hangers on loop "B" had gaps larger than the anticipated piping radial movement, thus piping thermal stresses and support loads were acceptable without further reanalysis as was the case with header "A". The licensee response also addressed the concern relating to the acceptance of headers "A" and "B" in Unit 2. The acceptability of the piping and supports were based on the following:

-- Similarity with Unit 1 piping and supports.

-- Unit 2 piping thermal stresses at 180°F (process temperature) are equal to or less than the corresponding Unit 1 piping stresses at 180°F.

-- The support gaps on Unit 2 hangers are larger than those on corresponding Unit 1 hangers.

The licensee's response to the remaining concerns was found acceptable. This item is closed.

1.2 (Closed) Violation (387/83-31-04; 388/83-31-04): Failure to Provide Timely Disposition Or Status Reports For 159 Nonconformance Reports

In December 1983, an inspector identified that 159 Nonconformance Reports (NCR's) were neither dispositioned within 30 days nor provided with a status report in accordance with Nuclear Department Instruction NDI-QA-8.1.5, Nonconformance Control and Processing. In addition, an earlier team inspection (50-387/83-30; 50-388/83-25) identified weaknesses in the licensee's timeliness in resolution of NCR's.

The licensee responded to the violation on February 25, 1984 (PLA-2087). The licensee's corrective actions included the following:

-- Administrative Procedure AD-QA-120, "Non-Conformance Reports - Control and Processing" was revised to provide a continuation form to be utilized by dispositioning organizations to provide status reports for those NCRs for which dispositioning could not be completed within the required time period.

-- Monthly NCR Status Reports were developed by the Plant Compliance Group and Quality Control (QC) to identify and trend NCR's with overdue responses to management and the responsible supervisors.

-- A NCR task force was created in January 1984 to meet 2 to 3 times a week to review the current status of NCR's and to assign priority categories for their closure. The task force was disbanded in June 1984, but the current NCR Coordinator meets on a routine basis with responsible groups.

-- Because a large number of the NCRs that had not been satisfactorily dispositioned were associated with receipt inspection activities, the licensee developed a separate reporting procedure related to receipt inspection. Therefore, the items subject to receipt inspection do not enter the PP&L quality system until after they have been accepted or conditionally released.

-- Nuclear Department Instruction NDI-QA-8.1.5 was revised to allow 45 days to disposition an NCR, rather than 30 days used previously.

The violation response was initially reviewed in Inspection Report 50-387/84-21; 50-388/84-26 in June 1984. The inspector reviewed the NCR Status Reports and noted that the licensee had significantly reduced the number of overdue NCR responses. However, it was determined that Nuclear Plant Engineering (NPE) had a large majority of the remaining overdue NCR responses and the item was left open pending licensee action to disposition NCR's issued to NPE in a more timely manner.

The inspector reviewed the revised procedures, the latest monthly status reports from Compliance and QC, and discussed the program with the responsible supervisors. The number of overdue NCR responses has been significantly reduced and management attention is evident. The latest Plant Staff Deficiency Status Report, dated March 11, 1987, states that there are 9 overdue NCR dispositions (3 Maintenance, 6 NPE). The report to the Plant Superintendent is provided to plant management personnel and the Vice President - Nuclear, and provides trends for total number of NCR's and overdue NCR's, and is broken down for responsible sections. NPE management has also taken action to provide more timely responses and to monitor NCR status more closely. Based on the program improvements, decreasing trend of overdue NCR's, and the management involvement in monitoring NCR trends, this item is closed.

1.3 (Closed) Violation (388/83-19-05): Temperature Elements Incorrectly Identified on Nameplates as Single Element Units Instead of Dual Element Units

In October 1983, the inspector identified that the Reactor Water Cleanup (RWCU) System dual element temperature units TE-G33-2N016A through F, TE-G33-2N022A through F and TE-G33-2N023A through F were identified incorrectly on nameplates as single element units.

The licensee responded to the violation on March 30, 1984 (PLA-2146). The corrective steps which were taken included installation of the proper (dual element) metal nameplates on the temperature units.

The inspector reviewed the documentation which corrected the discrepancies. The nameplate installation was not physically verified by the inspector due to the sensor location in a high radiation area.

1.4 (Closed) Inspector Followup Item (387/86-20-01): Procedure NDI-QA-6.5.1 Not Revised In a Timely Manner

In September 1986, the inspector determined that Nuclear Department Instruction NDI-QA-6.5.1, Radwaste Program, had not been revised since November 9, 1981, although the numerous annual reviews performed stated the procedure was to be revised.

The licensee issued the revised procedure NDI-QA-6.5.1, Revision 1, Low Level Radwaste, on December 30, 1986. The inspector verified that the revised procedure was distributed and had no further questions.

1.5 (Closed) Part 21 Report (387/86-11-01): Deficient Welds in Piping Systems of the Fifth Diesel Generator Auxiliary and Starting Air Skids

On June 30, 1986, a 10 CFR 21 notification was made to the NRC by Morrison-Knudsen Company, Inc. The notification stated that 63 of 700 welds in the piping systems of the Fifth Diesel Generator auxiliary and starting air skids were sized below code requirements. In addition, some component support welds were found undersized, and numerous surface defects, such as arc strikes, were identified.

Two nonconformance reports (NCR 781 and NCR 971) were issued by the constructor, Dravo Constructors, Inc. to document the deficiencies. Detailed dispositions for each weld and surface defect were determined during resolution of the NCRs. Some of the welds were accepted "use-as-is" based on further analysis and some arc strikes were determined acceptable, except in those cases where sharp discontinuities or measureable depth existed. The rework on the welds and surface defects requiring repair were completed on August 22, 1986.

The inspector reviewed the completed NCR packages which documented the repairs and the revised acceptance criteria for the "use-as-is" cases. The inspector had no further questions.

1.6 (Closed) Unresolved Item (387/82-36-02): Performance of Preservice Inspection of Recirculation System Pipe Welds

In August 1982, the licensee reported that portions of the required ASME Section XI Preservice Inspection examinations could not be performed on the recirculation system riser welds. In a letter dated August 17, 1982, the licensee requested partial relief from the Section XI examination requirements on the basis that an acceptable examination could not be performed in parts of the examination volume due to metallurgical and geometric restraints using state of the art ultrasonic techniques. Based on its review and evaluation of the request, the NRC granted the relief from preservice inspection requirements.

During both the preservice and the first inservice inspection on Unit 1, the licensee repeatedly attempted to volumetrically examine ten (10) recirculation system corrosion resistant clad (CRC) double weld joints. While ultrasonic examination is the most commonly used volumetric examination method utilized for Section XI weld examination, in this unique application, ultrasonic techniques met with minimal success, and MINAC radiography was the technique utilized for examination of the subject welds during the Unit 1 first refueling outage.

The inspector observed the performance of the examinations on these welds during inspections 50-387/82-36 and 50-387/86-05. On both occasions the inspector had concerns with the ability of the techniques to provide meaningful, repeatable results. The inspection problems were manifested by numerous ultrasonic indications which were attributed to the geometric and metallurgical condition of the materials comprising the welds, base material and cladding through which the ultrasonic beam must pass. The number of indications precluded a meaningful interpretation of the data.

Relief request IRR-6 of the Inservice Inspection Program was submitted to the NRC to address the difficulties associated with performance of these examinations. The relief request stated that due to geometric and metallurgical constraints, the heat affected zones and weld root of the subject components could only be partially examined. The licensee proposed alternative examination by visual examinations of the weld during system pressure tests required by 1WB-5000 of Section XI and volumetric examinations to the extent practical.

On February 18, 1987 the NRC approved the licensee's First Ten Year Interval Inspection Program and granted relief from the recirculation riser weld examinations. The Safety Evaluation Report concluded that adherence to the Code Requirements is impractical. It was further concluded that the proposed examinations would provide necessary assurance of structural reliability during the interval. Relief was approved provided:

-- volumetric examinations (both radiographic and ultrasonic) to the extent possible and visual examinations are completed, and

-- IGSCC indications revealed by radiography are evaluated further to the extent practical using ultrasonic techniques.

Based on NRC approval of the relief request this item is closed.

2.0 Routine Periodic Inspections

2.1 Operational Safety Verification

The inspector toured the control room daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. Instrumentation and recorder traces were observed and the status of control room annunciators was reviewed. Nuclear Instrument panels and other reactor protection systems were examined. Effluent monitors were reviewed for indications of releases. Panel indications for onsite/offsite emergency power sources were examined for automatic operability. During entry to and egress from the protected area, the inspector observed access control, security boundary integrity, search activities, escorting and badging, and availability of radiation monitoring equipment.

The inspector reviewed shift supervisor, plant control operator and nuclear plant operator logs covering the inspection period. Sampling reviews were made of tagging requests, night orders, the bypass log, Significant Operating Occurrence Reports (SOORs), and QA nonconformance reports. The inspector observed several shift turnovers during the period and routinely attended work planning meetings.

No unacceptable conditions were identified.

2.2 Station Tours

The inspector toured accessible areas of the plant including the control room, relay rooms, switchgear rooms, cable spreading rooms, penetration areas, reactor and turbine buildings, diesel generator buildings, ESSW pumphouse, the security control center, and the plant perimeter. During these tours, observations were made relative to equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping, security, tagging of equipment, ongoing maintenance and surveillance and availability of redundant equipment.

On March 10, 1987, the inspector conducted a tour of the Unit 1 and Unit 2 Reactor Buildings to review the implementation of the NCR Hold Tag program. During the walkdown the inspector identified 17 NCR Hold Tags posted in the plant which had not been removed when the associated NCR's were closed. The inspector also noted 10 NCR Hold Tags which had not been properly updated when the associated equipment had been Conditionally Released.

Nuclear Department Instruction, NDI-QA-8.1.5, Nonconformance Control and Processing, states that the QC Acceptance signature for the NCR closeout indicates the NCR is complete and the Hold Tags have been removed. However, the inspector identified 17 NCR Hold Tags (20 percent of the sample) that had not been removed when the NCR's were closed. The inspector discussed this discrepancy with the General Quality Control Supervisor (GQCS) and provided a list of the identified NCR Hold Tags to the licensee. Although the safety significance of this problem was minimal, since nonconformance tags were attached to conforming equipment, the inspector noted that this was not in accordance with station procedures, and could minimize the impact of the valid NCR Hold Tags. The GQCS stated that the tags would be removed immediately, and that a review of all NCR tags posted in the plant would be performed during the next quarterly tag verification. A spot check of the closed NCR documents for some of the identified tags determined that the NCR stated that the tag could not be located during closure and was assumed lost. The inspector reviewed the documentation for more recent NCR's and the tag locations are clearly noted on the NCR form. This notation was not utilized on the older NCR's, and thus may have contributed to the missing tags.

NDI-QA-8.1.5 also states that if a Conditional Release is approved for a component, QC shall update the status of the NCR and the associated NCR Hold Tags to identify the Conditional Release and any restrictions associated with the Conditional Release. During the walkdown the inspector noted 10 NCR Hold Tags for the MSIV two-way and three-way air operated valves and the drywell floor drain sump level probes which were not annotated that they had been conditionally released. The inspector discussed this discrepancy with the GQCS and he stated that the tags identified would be reviewed and corrected. Review of the NCR's determined they were properly annotated. Further review by the licensee found that the properly updated NCR tags had been issued but the old tags had apparently not been removed following approval of the Conditional Release.

On March 24, 1987 the inspector conducted a followup tour of the Reactor Building and verified that the closed NCR Hold Tags had been properly removed and that the Conditional Release Tags had been properly posted. The inspector had no further concerns.

2.3 Engineered Safety Feature (ESF) System Walkdown

On March 16 through March 20, the inspector performed an independent verification of the Unit 1 Low Pressure Coolant Injection (LPCI) System lineup by performing a complete walkdown of accessible portions of the system. The walkdown included the following:

-- Confirmation that the licensee's system check-off lists matched plant drawings and as-built configurations.

-- Identification of equipment conditions.

-- Inspection of breaker interiors.

-- Verification of properly valved-in instrumentation.

-- Verification of valve position, breaker position, and locking mechanisms.

The following minor discrepancies were noted:

-- Valves HV1F017A and HC1F017B, LPCI Injection Control Valves were not labeled.

-- Valve 151077, RHR Loop 'A' Drywell Spray Header Vent was not capped as specified in CL-149-0012.

The inspector discussed these discrepancies with licensee representatives and they stated that they would be corrected in a timely manner. The inspector had no further concerns.

3.0 Summary of Facility Activities

3.1 Unit 1

Unit 1 operated at or near full power for most of the inspection period. Scheduled power reductions were conducted throughout the period for control rod pattern adjustments, surveillance testing and scheduled maintenance.

On March 5, 1987 while performing repairs on steam leaks in the HPCI System a maintenance technician was injured when steam blew out of a valve packing. (See Detail 3.3)

On March 6, 1987 a lightning arrestor on the site's 12KV construction substation transformer failed, resulting in a momentary loss of startup transformer T-20. The voltage transient affected a number of systems on both units including initiations of the 'B' train of SGTS and CREOASS. Following the transient, power was restored to the startup buses and the systems were restored. The licensee made the proper ENS notification following the event.

3.2 Unit 2

Unit 2 operated at or near full power for most of the inspection period. Scheduled power reductions were conducted throughout the period for control rod pattern adjustments, surveillance testing and scheduled maintenance.

On February 26 and March 2, position indication on about 65 control rods was lost due to failed power supplies. (See Detail 3.4)

3.3 Maintenance Technician Injured During HPCI Steam Valve Packing Replacement (Unit 1)

On March 5, 1987 at approximately 2:58 p.m., a licensee mechanical maintenance technician received steam burns while replacing packing on the Unit 1 High Pressure Coolant Injection (HPCI) outboard steam supply isolation valve (HV-155-F003). The injured individual received second degree burns on his right leg and first degree burns to his face and left leg. A small amount of contamination was identified on his face but it was removed by HP prior to his leaving the site. He was transferred offsite at 3:27 p.m. and taken to Berwick Hospital by a Shickshinny Ambulance where he was treated and released. A second individual in the work area was not injured. The resident inspector monitored the licensee's response and recovery during the event from the control room.

Initial review of the event determined that while replacing packing on the outboard isolation valve, the length of pipe between the inboard and outboard isolation valve had not been adequately depressurized, and the packing blew out when the technician removed the packing gland. The initial blocking consisted of electrically closing the F003 valve, but steam was observed leaking from the packing and the work could not be performed. Manually closing the valve also did not reduce the leakage. The inboard steam isolation valve and bypass valve were then closed as an additional work boundary prior to the packing removal, and the leakage stopped. The technicians waited approximately three hours for the piping to cooldown and then began the valve disassembly. The Unit Supervisor pre-briefed the technicians on the potential for residual pressure in the system. It appears that the residual pressure remained high enough to unseat one disc of the split wedge gate valve and pressurize the valve body causing the packing to blow out when the technician removed the packing gland. The potential also existed that one of the inboard isolation valves was leaking.

Following removal of the injured individual from the area, the licensee was able to stop the steam leakage by depressurizing the system and backseating the valve. The inboard isolation valves were deactivated in the closed position to comply with Containment Isolation Technical Specifications.

Subsequent to the blow-out of the packing of the HPCI HV-155-F003 valve, the valve required a complete repack to be performed. Per the licensee's administrative programs (AD-QA-412 and AD-QA-502), this work required a post-maintenance local leak rate test to be performed. The LLRT requirement following a repack was based on the assumption that changes in the valve stroke due to frictional effects of new packing could potentially lead to a change in proximity of the disk to seat. The only accurate measure of this change is the local leak rate test. As this test requires the unit to be shutdown, other parameters were reviewed by the licensee to make a qualitative evaluation as to the effects of the repacking on this valve.

The alternate testing performed after the repack was not conclusive with respect to the invalidation of the previous local leak rate test. The strongest data to support no retest was the stroke time consistency. A pressurization test was performed to make a qualitative assessment of the leak tightness or seating of the F003 valve using steam at reactor pressure (LLRT is done at 45 psig, dry air). Initially, the system was pressurized to 980 psig, then the F003 was closed and the system was monitored for one hour. During this time the downstream pressure dropped to 500 psig, indicating leakage or

condensation in the system. The boundary was then depressurized, with the inboard isolation valves opened and the F003 closed. Pressure dropped to 30 psig and remained at 30 psig for the next 4 hours. The only conclusion which could be drawn from the test was that the valve was seating but no quantitative leak rate data could be determined.

In summary, the licensee determined that the valve was acceptable since: (1) No work was performed on the valve internals (seat or disk); (2) the repack work was done in a controlled manner consistent with previous successful repack work performed on this valve; (3) stroke time was consistent with previous test data; and (4) in-service inspection would be required to verify zero leakage observed at reactor pressure. Although the data accumulated did not constitute a substitute for an LLRT, it did indicate that the valve was consistent with its pre-work condition. The post-work stroke time was 31.26 seconds, which was consistent with the previous average of 31.72 seconds. The last LLRT was performed on April 13, 1986 with a total leakage of 122 ccm. The only work performed on the valve was to the packing, and it was the licensee's judgement that any gross changes due to frictional effects would have been demonstrated by a comparable change to the stroke time. Also there was no empirical evidence available to quantify packing changes to LLRT results. Therefore, it was recommended by PORC that the performance of a local leak rate test not be required, but should be performed during the next unit shutdown when a containment entry is planned.

The inspector reviewed the test result data and PORC meeting minutes and discussed the proposed actions with Plant Management. Further discussions with Region I management determined their actions to be acceptable. The results of the post-maintenance LLRT will be reviewed in a subsequent inspection (387/87-06-01).

3.4 Loss of Control Rod Position Indication (Unit 2)

On three separate occasions during the first quarter of 1987, February 10, 26, and March 2, position indication to a large number of control rods was temporarily lost. In each case, Rod Position Indication Inop Alarm on Control Room Panel 2C651 was received as designed and the operators responded by following the appropriate alarm response procedure actions. Technical Specification LCO 3.1.3.7 was properly entered and a 12-hour Action Statement initiated. In each case the RPIS was returned to operable status before shutdown of the unit was required.

The February 10 occurrence at 1:56 p.m. was traced to overheating of the relay room which caused a probe multiplexer card to fail. The relay room overheating was caused by a problem with the 'B' Control Structure Fan Chilled Water Valve controller (TIC-07802B) which was investigated and monitored for 2 weeks with no subsequent failures. No problems with the controller could be identified. The probe card failure resulted in decreased power output and loss of indication to 65 control rods. The card was replaced, the power supply reset, and the output and trip setpoint readjusted.

On February 26, at 1:45 a.m., the same power supply tripped on overvoltage causing loss of position indication to 65 control rods. This appears to be partially a result of readjusting the output and trip setpoint following the previous failure. According to the licensee, the output from the power supply had been increased to assure a minimum of 5 volts DC to the bus, however, the overtrip voltage is sensed directly at the power supply output. This, in effect decreased the margin to an overvoltage trip. In addition, the same temperature controller (TIC-07802B) was operating erratically and was therefore replaced and its proper operation verified. The power supply was reset and monitored for proper operation as the system was returned to service.

The third occurrence took place on March 2 at 6:40 p.m. due to a failure of an internal fan to the same power supply causing it to overheat. During repairs to the first power supply, a second power supply failed, due to a short circuit causing loss of position indication to an additional 25 control rods. At this time, rod drift alarm and rod overtravel alarms were received. This second power supply was replaced with a new one and the system returned to service. A rod drift and overtravel test were performed with acceptable results.

As of the end of this inspection period there have been no additional failures resulting in the loss of position indication to control rods. The licensee has written a new preventive maintenance procedure to replace the RPIS power supply fans every 18 months as a precautionary measure and plans to replace the power supply involved in all three occurrences the next time it fails.

3.5 Unauthorized Issuance and Use of Respirator

At 12:00 p.m. on March 13, 1987, a labor support foreman directed a worker to open a locked respirator storage cage and remove a respirator. He then directed a worker to don the respirator and enter a radiation work area located on the 818 foot elevation of the Unit 1 reactor building in order to replace two fuses in a hydrolaser. Health Physics personnel were not present during this evolution or made aware of it until afterwards.

Procedure AD-OO-725, Respiratory Protection Program, paragraph 4.5.3 indicates that it is the Health Physics Foreman's responsibility to assure that respiratory protective equipment is issued to and used by qualified personnel. In addition, the Respirator Training/ Retraining Course specifies that issuance of respirators will be performed by only Health Physics personnel.

A review of the individual's training records determined that he had received appropriate training in the use of respirators and should have been aware of the licensee's policy and procedures concerning their issuance.

Corrective action by the licensee included a disciplinary action for the foreman involved for violating station policy and procedures.

The inspector questioned the licensee to determine if they had considered incorporating more effective key controls. The licensee considers this an isolated occurrence since it is the first such occurrence and does not plan further actions.

Technical Specification 6.8.1 and Regulatory Guide 1.33, Appendix A, require written procedures covering respirator equipment to be established, implemented and maintained. The inspector concluded that this matter constitutes a licensee identified violation which meets the criteria of 10 CFR 2, Appendix C; therefore, a notice of violation will not be issued.

4.0 Licensee Reports

4.1 In-Office Review of Licensee Event Reports

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

Unit 1

*87-003, Diesel Generator Trip Alarm Investigation Necessitated Declaring One Diesel Generator Inoperable When a Second Diesel Generator Was Already Inoperable

*87-004, HPCI System Isolates Due To An I&C Technician Bypassing The Incorrect Isolation Logic During a Surveillance Test

87-005, Due To An Operator Error, Iodine Sampling Was Conducted Approximately 3 Hours Late Following a Power Change >15%/Hr.

87-006, Entry Into LCO 3.0.3 to Perform 4KV ESS Bus Degraded Voltage Relay Surveillances

Unit 2

*87-002, HPCI System Isolates Due To A Cognitive Error Made By An I&C Technician

*Previously discussed in Inspection Report 50-387/87-02; 50-388/87-02.

4.2 Containment Isolation Valve Actuation (Unit 2)

On March 20, 1987 at 12:30 p.m. the Unit 2 loop 'A' Containment Atmosphere Control Inboard Isolation Valves failed closed due to a blown fuse in the control power circuitry. The cause of the blown fuse was found to be an electrical fault in isolation valve SV25780A. The failed valve was electrically isolated and placed in the closed position. With the electrical fault isolated, the blown fuse was replaced and the remaining isolation valves were reopened. A work authorization (WA) was then generated to repair the valve.

During review of the associated Significant Operating Occurrence Report (SOOR), the inspector noted that the operating shift had determined the event not to be reportable per 10 CFR 50.72, and an ENS call was not made. Inspector review of the event found that the event was reportable in accordance with 10 CFR 50.72(b)(2)(ii), for any event or condition that results in manual or automatic actuation of any Engineered Safety Feature (ESF).

Discussions with the licensee staff determined that the operating shift had determined the event not reportable because of the nature of the actuation. An actual actuation signal had not been received. However, the licensee agreed that the event was reportable and correctly determined that an LER was required to be submitted describing this event. The LER will be reviewed during routine reviews in the next inspection period.

4.3 Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee were reviewed by the inspector. The reports were reviewed to determine that they included the required information; that test results and/or supporting information were consistent with design predictions and performance specifications; that planned corrective action was adequate for resolution of identified problems; and whether any information in the report should be classified as an abnormal occurrence.

The following periodic and special report was reviewed:

-- Monthly Operating Report - February, 1987, dated March 13, 1987.

The above report was found acceptable.

5.0 Monthly Surveillance Observations

The inspector observed the performance of surveillance tests to determine that: the surveillance test procedure conformed to Technical Specification requirements; administrative approvals and tagouts were obtained before initiating the test; testing was accomplished by qualified personnel in accordance with an approved surveillance procedure; test instrumentation was calibrated; limiting conditions for operations were met; test data was accurate and complete; removal and restoration of the affected components was properly accomplished; test results met Technical Specification and procedural requirements; deficiencies noted were reviewed and appropriately resolved; and the surveillance was completed at the required frequency.

These observations included:

-- SO-024-001B, Monthly Diesel Generator Operability Test, performed on the 'B' diesel generator on March 17, 1987.

-- TP-024, Fifth Diesel Generator Preoperational Test, performed on February 18, and March 4, 1987.

No unacceptable conditions were identified.

6.0 IE Information Notice Followup

IE Information Notice 87-08: Degraded Motor Leads In Limitorque DC Motor Operators

IE Information Notice 87-08, "Degraded Motor Leads in Limitorque Motor Operators", was issued on February 4, 1987 to alert licensees of potentially defective DC motors installed in Limitorque Motor Operators manufactured by H. K. Porter (Peerless-Winsmith) between December 1984 and December 1985. The motors are fitted with Nomex-Kapton insulated leads that are susceptible to insulation degradation and subsequent short circuit failure. In addition, these leads are presently not acceptable for use in an application requiring environmental qualification.

The inspector discussed this notice with the licensee to determine if any of the subject motor operators existed at the site and, if so, to determine the adequacy of their corrective actions. The licensee stated that they had five of the subject motor operators at the site. One is presently stored in the warehouse and the remaining four are installed in the Emergency Service Water System to the Fifth Emergency Diesel Generator.

The four valves installed in the Emergency Service Water System have had Ray Chem sleeving placed over the motor leads as a permanent fix to increase their dieletric strength, however, the sleeving has not been heat shrunk onto the leads since this location in the Fifth Diesel Building is not susceptible to a harsh environment as specified for environmental qualification. This corrective action appears adequate since failure occurred during normal operation in a non-harsh environment. The remaining motor operator stored in the warehouse is to be replaced prior to being installed in the plant.

The inspector had no further questions.

7.0 Use of Styrofoam in Reactor Buildings

During 1986, it was determined by the licensee that styrofoam forming material still exists in some areas in the seismic gap between primary containment and the reactor building in both units. Two NCRs, 86-0928 and 86-1018, were written to address the issue and a Significant Operating Occurrence Report (SOOR) 1-87-049, dated February 27, 1987, was written to determine reportability due to its effect on the fire hazards analysis. The licensee concluded that it was not reportable since the quantity of styrofoam remaining was too small to significantly contribute to the fire loading and/or endanger plant equipment. However, the licensee subsequently determined that the styrofoam must be removed due to its effect on the seismic loading. The seismic analysis assumes a minimal two-inch gap, but the styrofoam will only compress to one-inch.

Inspections of accessible areas for existing styrofoam is ongoing and Work Authorizations (WAs) have been initiated for its removal. Areas presently inaccessible are those such as high radiation areas which will be inspected and have the stryofoam removed if present during upcoming outages.

The inspector questioned whether the licensee had reviewed this for reportability based on its effect on the seismic analysis. Apparently, the licensee had not considered this, but is presently reviewing it for reportability. The inspector also questioned whether room I-511 which was the subject of FSAR Question 281.24 had the styrofoam removed as committed to by the licensee. However, the licensee was unable to answer this question and is researching documentation in an effort to resolve the issue. Since room I-511 is a high radiation area, it was not readily accessible for determination of the presence of styrofoam.

This item is unresolved pending review of the licensee's completed corrective actions (387/87-06-02).

8.0 Management Meetings

On April 6, 1987 the inspector discussed the findings of this inspection with station management. Based on NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain information subject to 10 CFR 2.790 restrictions.