UNITED STATES NUCLEAR REGULATORY COMMISSION

REGION I

Inspection Report Nos.	50-387/95-17; 50-388/95-17
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:	July 5, 1995 - August 5, 1995
Inspectors:	M. Banerjee, Senior Resident Inspector, SSES B. McDermott, Resident Inspector, SSES N. Blumberg, Project Engineer, DRP

Approved By: C. Anderson

C. Anderson, Chief
Reactor Projects Section 2B

8/29/95
Date

EXECUTIVE SUMMARY

Susquehanna Inspection Reports
50-387/95-17; 50-388/95-17
July 5, 1995 - August 5, 1995

Operations

Alert and cognizant control room operators operated both units in a safe manner with shift supervision providing good oversight (Section 2.1).

Maintenance/Surveillance

In preparation for the Unit 2 7th refueling outage, new fuel inspection activities were conducted in a safe manner with good supervision and engineering oversight (Section 3.3).

Engineering/Technical Support

PP&L's evaluation of the visqueen sheet retrieved from the suppression pool during the Unit 1 outage provided a reasonable assessment of its potential impact on the Reactor Core Isolation Cooling (RCIC) suction strainers and gave appropriate consideration to the potential for its transport to other areas of the suppression pool under dynamic conditions. The evaluation concluded that RCIC operability was not impacted during previous operating cycles with the visqueen sheet in the pool Section (Section 4.1).

Plant Support

An unannounced, after hour emergency plan call-out exercise revealed problems with PP&L's call-out procedure and the tele-notification system. Although the licensee's ability to respond in case of an actual emergency was maintained, PP&L took the necessary corrective actions and re-performed the call-out exercise with much improved results (Section 5.3).

Safety Assessment/Quality Verification

During the Unit 1 refueling outage, Operations management's decision not to enter the Technical Specification (TS) action called out by an emergency diesel generator test procedure is a violation. The safety significance of the incident was minimal, and this action reflected operations management's poor judgement, and was not willful. However, this violation is being cited, because the decision not to enter the required TS action was made by a higher level management personnel, and a previous Licensee Event Report in 1994 discussed the need to enter the TS action during the subject testing. Plant management has counseled operations management and reinforced the need to comply with plant TS. (Section 6.1).

A total of nine LERs and one unresolved item were reviewed and closed based on the inspectors assessment of the licensee's corrective actions.

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DETAILS

1. SUMMARY OF FACILITY ACTIVITIES

Susquehanna Unit 1 Summary

Unit 1 was operated at or near full rated thermal power throughout this inspection period. Minor power reductions were made to support main turbine valve testing, control rod pattern adjustment, and to reduce condenser backpressure resulting from extreme hot and humid weather.

Susquehanna Unit 2 Summary

Unit 2 remained at power throughout the inspection period, with routine power reductions for turbine valve testing and control rod pattern adjustments. Also, minor power reductions were required to reduce condenser backpressure on several unusually hot days. On Friday July 21, power was reduced to 58% for planned maintenance on the 'B' reactor recirculation motor-generator set and cleaning of the 'B' main condenser water box. As of Sunday July 23, power was returned to 100%.

2. PLANT OPERATIONS (71707, 92901, 93702)[1]

2.1 Plant Operations Review

The inspectors routinely observed the conduct of plant operations to verify independently that the licensee operated the plant safely and according to station procedures and regulatory requirements.

Control room indications and plant systems were observed independently by NRC inspectors to verify that plant conditions were in compliance with station operating procedures and Technical Specifications (TS). Control room alarms and bypass indication system (BIS) warnings were routinely reviewed and discussed with operators; Operators were cognizant of control board indications and plant conditions. Control room and shift manning were in accordance with TS requirements.

The inspectors conducted regular tours of the various plant areas and periodically reviewed logs and records to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication of equipment status. These records included various operating logs, turnover sheets, blocking permits, and bypass logs. The inspector observed plant housekeeping controls including control and storage of flammable material and other potential safety hazards. Posting and control of radiation, high radiation, and contamination areas were appropriate.

The inspectors performed backshift and deep backshift inspections during the period. The deep backshift inspections covered licensee activities between 10:00 p.m. and 6:00 a.m. on weekdays, weekends, and holidays.

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[1] The inspection procedure from NRC Manual Chapter 2515 that the inspector used as guidance is parenthetically listed for each report section.

Based on routine observations in the Unit 1 and 2 control room, the inspectors concluded that alert and cognizant operating crews had operated the plant in a safe manner following plant procedures, with shift supervision providing good oversight. Plant housekeeping was found acceptable.

2.2 Use of Overtime

The inspector reviewed the licensee's use of overtime by the unit staff who perform safety-related functions during the recently completed Unit 1 8th refueling outage. The inspector noted that in one case, a Nuclear Systems Engineer had worked in excess of 24 hours in a 48 hour time period. The plant technical specification section 6.2.2 limits the overtime to 24 hour in any 48 hour period for unit staff who perform safety related function. Upon inspector's questions, the licensee clarified that this engineer's use of overtime did not involve jobs directly related to a nuclear safety function (i.e., performing as a test director for test of safety-related equipment). However, the licensee prepared a deviation form to document this overtime use. Based on a sample review, the inspector concluded the use of overtime during the Unit 1 outage was consistent with the requirements of the plant Technical Specification (Section 6.2.2) and licensee's procedure NDAP-00-650, Conduct of Site Support.

3. MAINTENANCE AND SURVEILLANCE (62703, 61726, 92902)

3.1 Maintenance Observations

The inspector observed and/or reviewed selected maintenance activities to evaluate whether the work was conducted in accordance with approved procedures, regulatory guides, Technical Specifications, and industry codes or standards. The following items were considered, as applicable, during this review: Limiting Conditions for Operation were met while components or systems were removed from service; required administrative approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and quality control hold points were established where required; functional testing was performed prior to declaring the involved component(s) operable; activities were accomplished by qualified personnel; radiological controls were implemented; fire protection controls were implemented; and the equipment was verified to be properly returned to service.

Maintenance observations and/or reviews included:

- WA S15337, Perform 5 Year ESW Pump Inspection, August 3, 1995.
- WA P45409, Unit 2 Core Spray Pump 'B' Low Flow Check Valve Inspection, August 1, 1995.
- WA S50884, Unit 1 'A' Main Transformer Fan Cleaning, July 19, 1995.
- WA P51032, Megger and Polarization Testing of the reactor Core Spray Pump 'D' Motor, July 31, 1995.

Based on sample inspection of the above maintenance, the inspector concluded that the work was conducted and completed appropriately, with due concern for plant safety and procedures.

3.2 Preventive Maintenance of Core Spray Pump Motor

On July 31, 1995, the inspector observed WA P51032, Megger and Polarization Testing of the reactor Core Spray Pump 'D' Motor. This test is an 18 month periodic preventive maintenance test performed for each core spray pump. The inspector observed the test equipment readings and noted that the test data met acceptance criteria. The test meter was in calibration, and a quality control (QC) inspector witnessed the test as part of a QC sampling process for work on safety-related equipment. At the conclusion of the test, the inspector accompanied the electrical maintenance supervisor in the clearing of the tags, the work authorization (WA) documents, and the equipment release form (ERF). The inspector noted that the WA and the tagging authorizations are established and cleared electronically. The ERF was cleared manually in the control room. The overall maintenance activity was performed satisfactorily.

3.3 New Fuel Receipt Inspection

On July 26, 1995, the inspector observed new fuel receipt inspection activities on the refueling floor in support of the upcoming Unit 2 refueling outage. The inspector noted activities were performed following procedure OP-ORF-002, New Fuel Receipt and Inspection Activities, prerequisites were appropriately checked, good oversight of activities was performed by the Reactor Engineer, Maintenance Supervisor and the fuel vender representative. The inspection forms were duly completed, and the operability of new fuel vault criticality monitors were verified. The inspector concluded the licensee was performing the activity in an acceptable manner with good procedure compliance and supervision.

4. ENGINEERING (71707, 37551, 92903)

4.1 Evaluation Of Potential RCIC Suction Strainer Blockage

The Unit 1 suppression pool inspection, conducted during the Unit's 8th refueling outage, was to confirm the absence of debris that could clog emergency core cooling system suction strainers. During the inspection, the diver retrieved a sheet of visqueen (approximately 5' x 5') found hanging from the lower RCIC suction strainer bolts. Condition Report (CR) 95-150 was initiated to document this finding. In the past, visqueen was used to prevent accidentally dropping debris into the suppression pool, and has not been used after the 6th Unit 1 refueling outage. Since 1989, the licensee had documented debris that fell into the suppression pool. The licensee's program for foreign material exclusion controls, and suppression pool inspection were reviewed in NRC combined inspection reports 50-387/94-22; 50-388/94-23 and 50-387;388/95-08.

The RCIC suppression pool suction consists of upper and lower cone strainers mounted vertically to a "T" pipe, with each strainer having 100% capacity. Based on the location of the visqueen, it was postulated that the RCIC pump suction could draw the visqueen onto the strainers and block their flow. At the time of discovery, the Technical Specifications (TS) did not require RCIC to be operable and the CR did not address system operability. The visqueen was removed from the suppression pool and an evaluation for CR 95-150 was subsequently performed by Nuclear Systems Engineering. The safety assessment concluded that "...RCIC would have probably been able to perform its design function with suction from the pool." After reviewing this CR evaluation, the inspectors noted that it did not provide any detailed evaluation of the visqueen's potential impact and that it's conclusion was not definitive. The issue was left as an unresolved item (URI 95-08-02) pending the licensee's documentation and approval of an operability evaluation which addressed the ability of RCIC to perform its specified function.

A supplemental operability evaluation for CR 95-150 was written to address the potential impact of the visqueen on the RCIC suction flowpath during previous plant operation when the system was required to be operable. This evaluation compared the as-found geometry of the visqueen sheet to the physical configuration of the suction strainers and associated piping. The licensee concluded that the visqueen, if it had remained at the as-found location, could have blocked one of the strainers, but would not have had sufficient additional material to block the remaining 100% capacity strainer. The analysis also addressed postulated dislodging of the visqueen sheet during a LOCA and the potential for its impacting the ECCS suction strainers. In these scenarios, multiple strainers for redundant ECCS loops are available to assure reliability of the suppression pool cooling water source. Adequate ECCS capability would be maintained assuming the visqueen sheet was transported to, and blocked, one ECCS strainer.

The inspectors reviewed the licensee's documented evaluation, viewed a video tape of the diver's inspection, and discussed the issue with the responsible system engineer. The licensee's evaluation provided a reasonable assessment of the potential effects of the visqueen in the location it was found and gave appropriate consideration to the potential for transport to other areas of the suppression pool under dynamic conditions.

The inspectors noted that the licensee's CR operability determination addressed whether TS required RCIC to be operable, but it did not address the system's ability to perform its intended function. The subsequent evaluation by Nuclear System Engineering did address the function of RCIC but failed to include any detailed evaluation of the visqueen sheet's potential impact or a definitive conclusion regarding operability. The inspector considered these problems a weakness in the implementation of the CR process and operability determination procedure. However, the inspector concluded that the supplemental operability evaluation for CR 95-150 adequately addressed the impact of the visqueen sheet on the operability of RCIC and ECCS systems during previous operating cycles. This review closes URI 95-08-02 (see Section 6.2).

5. PLANT SUPPORT (71750, 71707, 92904)

5.1 Radiological and Chemistry Controls

During routine tours of both units, the inspectors observed the implementation of selected portions of PP&L's radiological controls program to ensure: the utilization and compliance with radiological work permits (RWPs); detailed descriptions of radiological conditions; and personnel adherence to RWP requirements. The inspectors observed adequate controls of access to various radiologically controlled areas and use of personnel monitors and frisking methods upon exit from these areas. Posting and control of radiation areas, contaminated areas and hot spots, and labelling and control of containers holding radioactive materials were verified to be in accordance with PP&L procedures. Health Physics technician control and monitoring of these activities was satisfactory. Overall, the inspector observed an acceptable level of performance and implementation of the radiological controls program.

5.2 Security (71707)

PP&L's implementation of the physical security program was verified on a periodic basis, including the adequacy of staffing, entry control, alarm stations, and physical boundaries. The inspector reviewed access and egress controls throughout the period. No deficiencies were found.

5.3 Unannounced Off-Hour Exercise

During an unannounced, after hour, emergency plan call-out exercise on July 20, 1995, completion of off-site notification, and the simulated manning of the emergency response facilities took longer than expected. The problem involved delays in activating the beepers, as well as, difficulties experienced by the responders in their ability to call-back through the tele-notification system that was overloaded. This resulted in the on-call Emergency Director (ED), among others, not being able to respond to tele-notification. The drill required the responders to call-back to the tele-notification system and confirm their fitness for duty and provide an estimated arrival time. The drill scope did not require the responders to physically respond to their assigned duty stations. It was also noted that completion of notification to Luzerne County, took longer than 15 minutes; and several responders stopped their attempted call-in, after a few attempts, when they found the tele-notification system to be jammed.

The licensee performed a review to determine root causes and needed corrective actions. The licensee concluded that although substantial delay occurred in the tele-notification process, in case of a real event, timely manning of the facilities would have happened. The on-call ED could not respond back to the tele-notification system but a back up ED personnel was available and in contact with the plant. The tele-notification system call-out sequence was noted as a major root cause of its overloading problem. A problem was also identified with the Luzerne County telephone, which was corrected.

To correct the tele-notification system weakness, the licensee implemented several changes. To facilitate manning of the emergency response facilities, the control room communicator flow chart was revised to require notification to security, for initiation of the tele-notification system, prior to the notification of the off-site agencies. To prevent overloading of the tele-notification system, the call-out sequence was revised to activate first the Technical Support Center (TSC) and the Interim Emergency Operations Facility (IEOF), and then the EOF as required. Also, the call-out priority setting was revised to include clerical positions at the very end of the call-out. A memo from the EP manager clarified the response procedure in case problems are experienced by the responders while calling into the system. With the above changes in place, the licensee ran another off-hour tele-notification system call-out on July 26, 1995. The changes were effective, and improved response was noted. Further refinement of the call-out process is being considered. As the call-out drills did not exercise physical manning of the emergency response facilities, another off-hour unannounced drill to demonstrate this ability is being considered.

The inspector reviewed the July 20, 1995 and July 26, 1995 drill call-out time-lines, the revised control room communicator flow chart, and hot box material provided to the control room operators that described the changes made to the call-out sequence. The inspector observed a shift supervisor instructing his shift about the hot box material. The inspector also reviewed the July 26, 1995 remedial drill critique, and discussed the issues with the emergency planning personnel. The inspector concluded the changes made to the call-out process were timely and effective. Licensee management provided appropriate emphasis on understanding and correcting the problem.

6. SAFETY ASSESSMENT/QUALITY VERIFICATION (92700)

6.1 Licensee Event Report Review

The inspector reviewed Licensee Event Reports (LERs) submitted to the NRC office to verify that details of the event were clearly reported, including the accuracy of the description of the cause and the adequacy of corrective action. The inspector considered whether further information was required from the licensee, and whether generic implications were involved.

The following LERs were reviewed, and the inspectors concluded the licensee met the reporting requirement, LERs provided the needed information, and the licensee's corrective actions were considered adequate:

<u>Unit 1</u>

95-003-00 Unit 1 Shutdown Due To Check Valve Surveillance Failure

On March 25, 1995, Unit 1 was shutdown from 100% power due to a failure of a reactor instrument line excess flow check valve. During the test, the valve failed to exhibit a significant decrease in flow at the point of draining. Excess flow check valve testing is done just prior to unit shutdown for refueling. The LCO was met since the unit was subsequently shutdown for the refueling outage. During the outage, it was determined that the valve could

not be repaired; and it was replaced. The cause of the failure has not yet been determined; however, the valve has been sent to the licensee's laboratory for analysis. The licensee determined that there were no generic implications, and the history of excess flow check valves in the plant indicates a low probability for this type of failure.

95-005-00 Missed Surveillance Test For 'D' Emergency Diesel Generator (EDG):

On March 29, 1995, during the Unit 1 Eighth Refueling Outage, an engineering review of past emergency diesel generator testing noted that a hot restart capability test of the 'D' EDG had not been performed during the Unit 2 Fifth refuelling outage (September-November 1992). The test was subsequently performed successfully on January 2, 1994, during the Unit 1 Seventh Refuelling Outage. The apparent cause was that a system test director misunderstood the test procedure requisite and assumed that a hot restart test performed on the 'E' EDG in March 1992 (during a time period when the 'E' EDG was substituting for the 'D' EDG) could be credited for the 'D' test.

Although the licensee has an automated surveillance authorization (SA) system, a procedural misinterpretation still allowed the test to be overlooked. 18 month surveillance testing procedures for the EDGs have all been changed to clarify when the hot restart test must be done. This incident appears to be an isolated occurrence which was caused, in part, by the fact that the 'E' EDG can be substituted for any of the other EDGs. The computer generated SA system would normally preclude missing a scheduled surveillance. This incident of technical specification non-compliance met the criterion of Section VII.B.1 in 10 CFR Part 2, Appendix C, and is not being cited.

95-006-00 Result of Local Leak Rate Test of a Main Steam Line Penetration Exceeds Limit

On April 1, 1995, during the Unit 1 Eighth Refuelling Outage, a main steam line (MSL) penetration local leak rate test through both the inboard and outboard main steam isolation valves (MSIVs), indicated that the leakage of 53 standard cubic feet per hour (SCFH) exceeded the required total MSL containment penetration leakage of 46 SCFH. The exact cause of the leakage of the valves was not known; but the leakage was apparently caused by some corrosion on the valve seats. Stroking of the 'A', 'C' and 'D' inboard MSIVs and the 'D' outboard MSIV significantly reduced the leakage rate to 21 SCFH. There have been past incidents of MSIV leakage, but the leakage did not affect the integrated containment leak rate test.

The licensee has submitted a Technical Specification change to raise the leakage limits to 100 SCFH for any one MSIV and to 300 SCFH for all MSIVs combined. This request is currently under review by the NRC. Based on the licensee's analysis for offsite and control room dose, the leakage was of low safety significance. If Technical Specification is approved, the current "as found" leakage during tests should normally be below the required limits. (Post inspection note: the NRC, on August 18, 1995, approved this technical specification change).

95-007-00 **Unplanned ESF Actuation of RPS Due to Spurious Instrumentation Upscale Signal**

This LER documents initiation of a scram signal during the recently completed Unit 1 refueling outage, while the RPS was in the non-coincident trip mode, due to spurious intermediate range neutron monitor (IRM) upscale signals. During the time, control room operators were performing control rod stroke time and friction testing, and in accordance with the plant procedure shorting links were removed to initiate a full scram signal from the trip of any one of the two RPS channels.

Spurious signal spiking of the IRMs has been observed on numerous occasions during refueling outages when neutron flux levels are low and the IRMs were at their lower ranges. At these ranges instrumentation is more susceptible to noise due to high system gain. The licensee conducted an investigation to identify the source of the noise, but a source was not identified. However, one of the two IRMs associated with the event had a lower than desirable detector resistance to ground, and the licensee believed that had contributed to the event. The licensee plans to replace the degraded detector during the next refueling outage. The licensee is also evaluating the requirement of removing the shorting links to support control rod testing and intends to pursue it as a part of their technical specification improvement.

The inspector concluded the safety significance of the event was minimal.

95-008-00 **Unplanned ESF Actuation - 'B' Emergency Diesel Generator Automatic Start**

On April 27, 1995, an unplanned automatic start of the 'B' Emergency Diesel Generator (EDG) occurred due to physical bumping of a 125V DC circuit breaker. The circuit breaker, located inside the diesel generator control panel was found in the open position. Due to the loss of the 125V DC control circuit, although it started, the 'B' EDG would not have properly loaded had it been called upon to do so. The other three EDGs were operable. The breaker was subsequently reclosed, and the EDG successfully tested. The breaker was replaced with a breaker from the same manufacturer/model number. The licensee plans to test the removed breaker at a future date.

The licensee indicated the breakers, provided by Heineman, are not used in any other safety-related applications in the plant. The licensee considered the incident isolated and their review with the Cooper Bessemer Owners Group did not identify any generic concern with the breaker. Regarding physical bumping of the breaker, a task team at Susquehanna is currently reviewing various known incidents of human performance errors, and developing ways to improve human performance.

Unit 2

95-001-00 Operation at Power with an Inoperable Excore Neutron Flux Monitor

On January 30, 1995, while Unit 2 was at 100% power, the Excore Neutron Flux Channel 'B' log power range indicator failed and was reading upscale. The condition could not be corrected. A notice of enforcement discretion (NOED) was obtained from the NRC on February 6, 1995, to allow continued plant operation. Operation in this condition was allowed until the next refueling outage scheduled to begin in September 1995. Technical issues and licensee actions concerning this LER were discussed in NRC Inspection Report 95-02.

95-002-00 Unplanned Engineering Safety Feature (ESF) Actuation Due to Operator Switching Error

On February 8, 1995, with Unit 2 at 100% power, an unplanned ESF actuation occurred when a normally open primary containment isolation valve for the Traversing Incore Probe (TIP) Indexer automatically closed following the de-energization of a 120 volt power supply circuit. The cause of the problem was operator error in that during a routine work evolution a blocking tag was applied to a number 13 breaker instead of the called for number 3 breaker. The error was discovered about three hours later by an electrician who was verifying electrical blocking for a scheduled maintenance activity.

Status indication of six pieces of equipment was lost, and an ESF actuation occurred when normally open primary containment isolation valve for TIP Indexer automatically closed following de-energization of the power supply. There were no alarms in the Control Room, but status indication for the valve, which is located on a back panel, was lost. This loss of indication was not noticed by Control Room operators during a shift turnover panel walkdown. Corrective action included retraining of nuclear plant operators and control room operators on the weaknesses that caused this event. Regarding the human performance aspect of the event, a licensee task team is currently reviewing the human performance error events to develop comprehensive corrective actions.

95-006-00 Condition Prohibited by the Plant's Technical Specification (LCO 3.0.3)

During the recently completed Unit 1 refueling outage, the licensee performed an 18 month surveillance of the Emergency Diesel Generators (EDG) and Engineered Safeguards System (ESS) Buses on Loss of Offsite Power with a LOCA. This test is performed on each division of EDGs at a time, thus affecting two EDGs and two ESS buses. During the testing, the auto-close permissive relays for the primary and feeder breakers to the subject ESS buses are de-energized, and undervoltage start signals to the respective EDGs are bypassed. This ensures verification of automatic start of the subject EDGs upon a LOCA signal and subsequent sequential loading of safety-related equipment on the respective ESS buses. Since the EDGs are shared between the two units, and the Unit 1 buses carry loads common to both units, entry into a Unit 2 technical specification (TS) limiting condition of operation (LCO) is required when any of these Unit 1 ESS buses are not energized. By virtue of removing

the main and alternate feeder auto-closing features from two of the Unit 1 ESS buses, these buses are considered de-energized. As the Unit 2 TS does not address de-energizing two ESS buses the test procedure specifies entry into LCO 3.0.3 for Unit 2. LCO 3.0.3 requires that within one hour actions be taken to enter hot shutdown in 12 hours and cold shutdown in following 24 hours.

During Division I testing, the licensee entered into LCO 3.0.3, as it did during the previous performance of this 18 month surveillance. But, during Division II testing, operations management made a determination that such an entry was not required. This decision was contrary to the guidance provided in the licensee's test procedure and Technical Specification (TS) Interpretation (TSI) document No. 2-88-001. Also, during the previous Unit 1 outage the licensee determined that entry into LCO 3.0.3 was necessary during performance of the subject test, and an LER (94-001) documented this entry. The operations management was counseled by plant management, and is reviewing the TSI 2-88-001 with the licensed operators regarding the need to enter LCO 3.0.3 during performance of this test. The licensee is currently preparing a TS change for submittal to the NRC that will preclude need for entry into LCO 3.0.3 during the testing. The NRC inspector was informed that, pending a TS change, this LCO will be entered during future performance of the test.

The inspector reviewed the LER, the test procedure steps and had discussions with operations management, the test engineer and the licensing engineers. The inspector concluded that the actual safety significance of not entering LCO 3.0.3 was minimal, as the respective buses were continually energized during the test except for 10 seconds from bus de-energization to re-energization by the EDGs. As the main and alternate feeder breaker auto-closure protective features were bypassed, if an EDG failed to re-energize the bus, manual action would have been necessary to remove the bypasses and energize the bus. The test procedure required positioning nuclear plant operators at the breaker locations, hence the needed actions can be taken promptly. The inspector concluded that the licensee's decision not to enter LCO 3.0.3 in this case was a violation of plant technical specifications. This violation is being cited, because the decision was made by a higher level management personnel, and the need to enter the technical specification required action during the subject testing was previously identified by the licensee, as reflected in LER 94-001. (VIO 50-388/95-17-01)

95-007-00 Local Leak Rate Testing Not Performed on Two Electrical Penetrations Since Original Construction

On February 27, 1995, work planning reviews to support Unit 2 containment local leak rate testing (LLRT), identified that two electrical penetrations used for the Excore Neutron Monitoring System had not been local leak rate tested since original construction in 1983. The penetrations had been local leak rate tested during pre-operational testing; however, through an oversight, the need to leak rate test these penetrations was not transferred to licensee documents.

As a corrective action, the licensee reviewed all plans and documents and performed a walkdown of the containment penetrations to ensure that LLRTs have been performed. No further discrepancies were found. 27 penetrations, which are located in inaccessible or high radiation areas, will be visually verified to be spare penetrations, and do not require LLRT, during the upcoming Unit 2 Seventh Refuelling Outage starting in September 1995. In addition, the licensee performed an LLRT on the two penetrations and both passed.

6.2 Open Item Followup

(Closed) URI 50-387;388/95-08-02, RCIC Suppression Pool Suction Blockage

This unresolved item is closed based on the inspector's review documented in section 4.1 of this report.

6.3 10 CFR Part 21 Reports

Ethylene Glycol Fill Liquid in ITT Barton Differential Pressure (D/P) Indicators and Differential Pressure Indicating Switches

An ITT Barton Industry advisory dated March 13, 1995, stated that for certain Model Gages filled with ethylene glycol, the ethylene glycol may disassociate in radiation fields in excess of 1E6 RADs.

The licensee reviewed its environmental qualification (EQ) data base for all ITT Barton D/P switches regardless of filling. Only two D/P switches were found to have the potential for being exposed to fields in excess of 1E6 RADs. These switches are used for initial operation of the HPCI system. Based on a review of the environmental profile of the areas where these switches are located, the licensee concluded that the switches would no longer be needed when the radiation fields ultimately exceeded those in the advisory. Based on this review, the licensee determined that there is not a problem at SSES.

The review by the licensee for this issue was both prompt and comprehensive.

7. MANAGEMENT AND EXIT MEETINGS (71707)

7.1 Resident Exit and Periodic Meetings

The inspector discussed the findings of this inspection with PP&L station management throughout the inspection period to ensure timely communication of emerging concerns. At the conclusion of the reporting period, the resident inspection staff conducted an exit meeting summarizing the preliminary findings of this inspection. 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.

7.2 Other NRC Activities

The following region based NRC inspection activities/management visits took place during this period:

Dates	Report No.	Inspection Procedure	Lead Inspector
July 24 - 28	95-17	64704, Fire Protection	Harrison
July 24 - 28	95-19	84750, Effluent	Jang
July 18 & 27	----	SALP Board Members Visit	----