February 6, 2003

Mr. Harold W. Keiser
Chief Nuclear Officer and President
PSEG Nuclear LLC - N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION - NRC INSPECTION REPORT 50-272/02-09, 50-311/02-09

Dear Mr. Keiser:

On December 28, 2002, the NRC completed an inspection of Salem Unit 1 and Unit 2 reactor facilities. The enclosed report documents the inspection findings which were discussed on January 16 , 2003 with Mr. Lon Waldinger and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. Specifically, this inspection involved three months of resident inspection and region-based inspections by radiation protection, emergency preparedness, security and in-service inspection specialists.

Based on the results of this inspection, the inspectors identified four issues of very low safety significance (Green). All of these issues were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as non-cited violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

Additionally, an unresolved item discussed in Inspection Report 02-07 involving the failure to maintain the automatic fire suppression systems in six electrical areas was fully evaluated using the significance determination process during this period and found to be of very low significance (Green).

If you deny the non-cited violations noted in this report, you should provide a response with the basis for your denial within 30 days of the date of this inspection report to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with copies to the Regional Administrator, Region I; the Director, Office of Enforcement; and the NRC Resident Inspector at the Salem facility. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/reactors/operating/oversight.html.

Since the terrorist attacks on September 11, 2001, the NRC has issued two Orders (dated February 25, 2002 and January 7, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. The NRC also issued Temporary Instruction 2515/148 on August 28, 2002 that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the February 25th Order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year (CY) ‘02, and the remaining inspections are scheduled for completion in CY ‘03. Additionally, table-top security drills were conducted at several licensees to evaluate the impact of expanded adversary characteristics and the ICMs on licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Security and Incident Response. For CY ‘03, the NRC will continue to monitor overall safeguards and security controls, conduct inspections, and resume force-on-force exercises at selected power plants. Should threat conditions change, the NRC may issue additional Orders, advisories, and temporary instructions to ensure adequate safety is being maintained at all commercial power reactors.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Glenn W. Meyer, Chief
Projects Branch 3
Division of Reactor Projects

Enclosure: Inspection Report 50-272/02-09, 50-311/02-09
Attachment: Supplemental Information

Docket No. 50-272; 50-311
License No. DPR-70; DPR-75

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	50-272/2002-09, 50-311/2002-09
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Salem Nuclear Generating Station, Unit 1 and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	October 1 - December 28, 2002
Inspectors:	Raymond K. Lorson, Senior Resident Inspector Fred L. Bower, Resident Inspector Michael C. Modes, Senior Reactor Inspector Dave Silk, Senior Emergency Preparedness Inspector Gregory C. Smith, Senior Physical Security Inspector Jason Jang, Senior Radiation Specialist Joseph T. Furia, Senior Health Physicist Frederick Jaxheimer, Reactor Inspector Suresh Chaudhary, Reactor Inspector Roy L. Fuhrmeister, Senior Reactor Inspector
Approved By:	Glenn W. Meyer, Chief, Projects Branch 3 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000272-02-09, IR 05000311-02-09, Public Service Electric Gas Nuclear LLC, Salem Unit 1 and Unit 2 on 10/1 - 12/28/02, Heat Sink Performance, Fire Protection, Emergent Work, Refueling and Outage, and Temporary Modifications.

The report covered three months of inspection by resident inspectors and also included inspection by regional specialists in radiation protection, fire protection, security, emergency preparedness and in-service inspection. This inspection identified five green issues which were non-cited violations (NCVs). The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, *Significance Determination Process* (SDP). Findings for which the SDP does not apply may be “Green” or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, *Reactor Oversight Process*, Revision 3, dated July 2000.

A. Inspector Identified Findings

Cornerstone: Mitigating Systems

- **Green**. The inspectors identified that the thermal performance testing of heat exchangers in the component cooling water (CCW) system was inadequate, in that readily apparent CCW flow rate errors existed.

  This NCV of 10 CFR 50, Appendix B, Criterion VI, “Test Controls,” is greater than minor, because it affected the Mitigating System Cornerstone objective of equipment reliability, in that inadequate test controls could allow a degraded heat exchanger to go undetected. This finding was of very low significance, because the CCW heat exchangers remained operable when the flow measurement errors were corrected in subsequent evaluations.   Also, this finding had an aspect of problem identification and resolution, in that an apparent error was not identified. (Section R07)

- **Green**. The inspectors identified that the records of troubleshooting and repair activities on the 1PR2 valve and on the 22 containment fan cooling unit were incorrect and incomplete.

  This NCV of TS 6.10.1.b (records) was greater than minor, because it impacted the inspectors’ ability to independently assess the condition of these components following maintenance activities and it affected the Mitigating Systems Cornerstone equipment reliability objective. This finding was of very low significance, because the components performed acceptably during the post-maintenance testing. Also, this finding had an aspect of problem identification and resolution, in that it indicated that corrective actions for a previous, similar violation (IR 2001-12) had not been effective.   (Section R13)

- **Green**. A required decay heat removal support system (11 CCW room cooler) was removed from service at conditions not permitted by Technical Specifications (TS) (refueling cavity level less than 23 feet.)

  An NCV of TS 6.8.1 was identified for failure to establish and implement adequate procedures to control the removal of the 11 CCW room cooler from service for maintenance. This finding was greater than minor, because it affected the Mitigating System Cornerstone objective of equipment availability, in that it resulted in a condition where two residual heat removal systems were not operable when required by TS. The finding was determined to be of very low significance, since the 11 CCW pump remained functional when the fan was out of service without the necessary compensatory measures. (Section R20)

- **Green**. The inspectors identified that a temporary modification (hose connection and pump) to an operable service water header was not properly evaluated.

  This NCV of 10 CFR 50, Appendix B, Criterion III, Design Controls was greater than minor, because it affected the Mitigating System Cornerstone objective of equipment reliability, in that it could have affected the operability of the only service water header while reactor de-fueling operations were in-progress. This finding was determined to be of very low significance, as the service water header remained functional while the hose was attached. (Section R23)

- **Green**. PSEG did not properly maintain room isolation barriers and improperly implemented a modification to the switchgear penetration area ventilation system, both of which caused an existing fire protection concern on carbon dioxide (CO_2) concentration to be exacerbated. This finding represents the completion of an unresolved item identified in Inspection Report 2002-07 regarding the automatic fire suppression system in six safety-related electrical areas addressed by the fire protection program.

  When fully evaluated, this finding was determined to be an NCV for failure to maintain the fire protection program as required by License Conditions 2.C.5 (Unit 1) and 2.C.10 (Unit 2). The finding was greater than minor, because it adversely affected the Mitigating System Cornerstone objective regarding fire suppression equipment capability. The finding was determined to be of very low significance due to the multiple trains of mitigating systems which would have survived postulated fire events. Also, this finding had an aspect of problem identification and resolution, in that ineffective problem evaluation existed regarding the preventive maintenance and modifications on the affected equipment. (Section OA5.3)

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Report Details

SUMMARY OF PLANT STATUS

Unit 1 began the period at full power. On October 10, 2002, the unit was shutdown to begin refueling outage 1R15 (Section R20). On November 5 the unit was taken critical and power ascension continued until November 12 when the unit was returned to full power. On November 12, the unit was manually tripped in response to a lowering steam generator water level condition. The event was investigated and the unit was returned to a critical mode on November 12 (Section R14). The unit operated at approximately full power for the remainder of the period with the exception of power reductions performed at the request of the off-site load dispatcher.

Unit 2 operated throughout the period at approximately full power with the exception of power reductions performed at the request of the off-site load dispatcher.

1. REACTOR SAFETY

Initiating Events, Mitigating Systems, and Barrier Integrity [Reactor - R]

1R01 Adverse Weather Protection

a. Inspection Scope

On December 10 the inspectors performed a walkdown of the Salem Unit 1 and Unit 2 service water (SW) system, refueling water storage tanks, auxiliary feedwater storage tanks, and related heat trace systems to review whether preparations for cold weather conditions were appropriate and consistent with operations procedure, SC.OP-PT.ZZ-0002(Q), "Station Preparations for Winter Conditions." The inspectors also reviewed S1.OP-AB.ZZ-0001(Q), "Adverse Environmental Conditions," to determine whether PSEG had defined responsibilities for tornados, hurricanes and high wind conditions.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

The inspectors performed two partial system walkdowns during the Unit 1 refueling outage (1R15). On multiple days the inspectors walked down the 1 SW bay while the 3 SW bay was removed from service for maintenance. The inspectors also walked down the redundant emergency diesel generators (EDGs) while the EDG associated with the out-of-service SW bay was removed from service. Each Unit 1 EDG was removed from service for maintenance during 1R15. To evaluate the operability of the selected train or system when the redundant train was out of service, the inspector checked for correct valve and power alignments by comparing the positions of valves, switches and electrical power breakers to system diagrams. The inspector also verified that key standby and support system process parameters were acceptable to support operation of the redundant equipment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Fire Area Walkdowns

a. Inspection Scope

During the weeks beginning on December 15 and December 22, the inspectors walked down accessible portions of six areas described below to assess PSEG's control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and any related compensatory measures. As part of the inspection, the inspectors reviewed fire protection procedure, NC.NA-AP-0025, "Operational Fire Protection Program," and engineering document, DE.PS.ZZ-0001-A2-FHA, revision 5, "Salem Fire Protection Report - Fire Hazards Analysis," to ascertain the requirements for required fire protection design features, fire area boundaries, and combustible loading requirements for these areas. The following areas were reviewed:

- 11 and 12 Diesel Fuel Oil Transfer Pump Rooms (fire areas 1FA-DG-84H and 1FA-DG-84G)
- Unit 1 and Unit 2 Carbon Dioxide Equipment Rooms (fire areas 1FA-DG-84F and 2FA-DG-84F)
- 21 and 22 Diesel Fuel Oil Transfer Pump Rooms (fire areas 2FA-DG-84H and 2FA-DG-84G)

The inspectors reviewed the following notifications to determine whether PSEG appropriately addressed these issues in accordance with their corrective action program:

- Notification 20125638 which identified the failure to close fire impairment permits when repairs to fire barriers were completed.
- Notification 20127260 which documented an inspector identified issue involving two potentially degraded fire barrier seals (Unit 1).
- Notification 20125301 which involved excessive cycling of the carbon dioxide tank compressor (Unit 1).

b. Findings

No findings of significance were identified.

.2 Unannounced Fire Drill Observation

a. Inspection Scope

The inspectors observed an unannounced, off-hours fire drill on December 4, 2002. The drill involved having the fire brigade respond to a simulated electrical breaker fire in the safety-related 84 foot elevation electrical switchgear room at Salem Unit 2. The inspectors verified that the fire brigade responded to the hazard area with appropriate breathing apparatus, protective clothing, and fire fighting equipment. Additionally, the inspectors verified that the fire brigade leader adequately directed the actions of the fire brigade, referred to the fire fighting response procedures and communicated the fire status to the plant operators. The inspectors also verified that the fire brigade established a monitor to ensure that the fire did not re-flash and searched the area for potential fire victims, and also observed the post-drill critique.

The inspectors reviewed notification 20125652 which identified a deficiency in the development of the fire drill scenario and notification 20125656 which identified that a notification was not promptly developed for the scenario deficiency to assess whether PSEG was appropriately entering items into the corrective action program for resolution.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed flood protection measures for external sources as described in the Individual Plant Examination for External Events. The inspectors reviewed procedure SC.MD-PM.ZZ-0036, “Watertight Door Inspection and Repair,” and selected completed watertight door inspection records. The inspectors also reviewed procedure SC.FP-SV.FBR-0026, “Flood and Fire Barrier Penetration Seal Inspection,” and selected 2002 completed flood seal inspection records. The inspectors observed that seal discrepancies were documented in notification 20102951. This inspection also included tours of various plant areas including 64 feet and 84 feet electrical switchgear rooms for Units 1 and 2 that were identified as risk significant. The inspector located and toured an underground service water pipe and cable tunnel with PSEG engineering personnel. The inspectors noted what appeared to be groundwater dripping from several conduit seals. Sump pumps in this area had discrepancies which appeared to prevent automatic operation.

The inspectors also attempted to locate and inspect additional underground bunkers/manholes subject to flooding that contained risk-significant cables. At the conclusion of the inspection period, PSEG had not identified and provided access to all underground cable vaults with safety-related cables. PSEG initiated notification 20127365 to inspect the safety-related cable vaults at Salem. PSEG was also evaluating their underground cables to determine whether the cables were qualified for wetted or submerged service. PSEG initiated notification 20105022 to capture these issues in the corrective action program. At the completion of this inspection period, the engineering evaluation (order 80048125) for these issues had not been completed. Therefore, the inspectors were unable to determine whether PSEG implemented appropriate corrective actions for industry operating experience related to submerged safety-related electrical cables. This issue remains unresolved pending further review of PSEG's actions for submerged safety-related electrical cables. **(URI 50-272 and 311/02-09-01)**.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed 12A and 12B CC system heat exchanger performance test data collected on October 11, 2002, to verify that the heat exchangers met the performance requirements and assumptions specified in engineering calculation, S-C-CC-MDC-1798, revision 3, "Component Cooling System Heat Exchangers." Additionally, the inspectors examined service water and component cooling system drawings, reviewed operations procedure, S1.OP-PT.SW-0017, "12 Component Cooling Heat Exchanger Heat Transfer Performance Data Collection," and interviewed a design engineer to verify that the test methodology accounted for instrument inaccuracies and differences between test and design basis conditions.

The inspectors also reviewed notification 20125915 which documented inspector identified performance test deficiencies to ensure that PSEG appropriately entered these issues into the corrective action program for resolution. One of the deficiencies involved the failure to maintain the data acquisition system test data as required by procedure S1.OP-PT.SW-0017. The failure to maintain this quality record affected the inspectors' ability to confirm that the average test data values were representative of the individual test data samples and was similar to the findings discussed Section R13.

b. Findings

Introduction. The inspectors identified that the thermal performance testing of heat exchangers in the component cooling water (CCW) system was inadequate, in that readily apparent CCW flow rate errors existed. This finding was determined to be of very low significance and was considered a non-cited violation of Appendix B, Criterion XI, "Test Control."

Description. The thermal performance testing of the 12A and 12B CC heat exchangers was performed in accordance with operations procedure S1.OP-PT.SW-0017. The test was designed to compute the fouling factor for each heat exchanger based on measured SW and CC system process parameters.

The inspectors identified that the flow values recorded for the CC heat exchangers (CC side) were less than the values recorded for the same flow stream through the residual heat removal (RHR) heat exchanger (i.e. 2636 gpm for the 12B CC heat exchanger vs 3000 gpm for the RHR heat exchanger). This was a readily apparent discrepancy since the flowrate through the CC heat exchanger, which supplied both the RHR heat exchanger in addition to other loads, should have been larger than the CC flowrate through the RHR heat exchanger.

This flow discrepancy introduced a non-conservative error into the determination of the 12A and 12B CC heat exchanger fouling factors. A PSEG engineer re-computed the fouling factors assuming the higher flow values and determined that the heat exchangers remained operable.

Analysis. The inspectors determined that this finding was associated with the procedural quality attribute that affected the reliability objective of the Mitigating Systems Cornerstone to properly monitor the CC heat exchanger thermal performance, and is therefore greater than minor. If left uncorrected, this finding could result in a more significant safety concern (i.e. the failure to identify unacceptable CC heat exchanger performance through testing). This finding was evaluated using the Phase I worksheet of the significance determination process (SDP) and determined to be of very low risk significance (Green), since the CC heat exchangers remained operable when the flow measurement error was corrected. Also, this finding had an aspect of problem identification and resolution, in that an apparent error was not identified.

Enforcement. 10 CFR 50, Appendix B, Criterion XI, “Test Control,” requires, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures. Contrary to the above, PSEG failed to develop adequate procedural controls for measuring the flow through the CC heat exchanger during thermal performance testing. Because the failure to adequately measure the flow through the CC heat exchanger during thermal performance testing was determined to be of very low significance and has been entered into the corrective action program (notification 20129515), this violation is being treated as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-272/02-09-02, Failure to Properly Test the 12 Component Cooling Heat Exchanger.

1R08 Inservice Inspection Activities

.1 Inservice Inspection

a. Inspection Scope

The inspector reviewed the repair of the refueling water storage tank (RWST) to assure it was in compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Code). The inspector also reviewed whether PSEG addressed the pre-repair condition of the RWST in accordance with ASME Code requirements as discussed in Inspection Report 50-272/01-07 (unresolved item (URI) 50-272/01-07-01).

The inspector reviewed the work order implementing the visual examination of the reactor head of Unit 1, which included photographic examples of penetration leaks from Surry, Oconee, Davis Besse, and Crystal River 3, in order to evaluate the scope of the visual inspections undertaken by PSEG in response to NRC Bulletin 2002-002. The inspector reviewed the visual examination procedure and the qualifications of the individuals implementing the visual inspection. The inspector reviewed the disposition of the visual examination of the head, which indicated there was no evidence of leakage of any kind, either from the head penetration or the canopy seal. With the inspection personnel who performed the inspection of the reactor head, the inspector discussed the visual evaluation of developer residue remaining on some of the canopy seal welds. Additionally the inspector reviewed the supporting documents for a number of nondestructive examinations that had been completed to determine their compliance with the ASME Boiler and Pressure Vessel Code requirements.

The inspector reviewed the Salem Unit 1 Steam Generator Program, Steam Generator Aging Management Program, and Steam Generator Operational Assessment. The inspector observed the location verification for the acquisition of automated eddy current data taken from steam generator 14, Column 11, Row 62 taken simultaneously with data from a tube located at Column 11, Row 63, using the Framatome ROGER manipulator, to verify the data set was controlled and opportunities were introduced in the data collection process to capture location errors that might cause data offsets. The inspector reviewed, with the independent Level III eddy current data analyst, the anomalous eddy current drift data of steam generator 14 in the tube located at column 10, row 83, the tube located at column 4, row 75, and the tube located at column 2, row 85.

The inspector reviewed the data to determine if PSEG was taking into account the lessons-learned at Seabrook Unit 1 steam generators because the Salem Unit 1 generators were purchased from Seabrook Unit 2 as replacement generators and are identical in critical areas to Seabrook Unit 1. The inspector discussed the increase in the number of anti-vibration bar wear indications between refueling outage 13 and 14 in order to ascertain what evaluations had been performed. The inspector reviewed the disposition of loose parts in steam generator 11 at tube location Row 1 Column 3 and in steam generator 14 at location row 2, column 23. In addition, the inspector discussed, with the independent eddy current analyst and PSEG steam generator principal engineer, the current evaluation of the previously discovered loose parts at row 42, column 62 and column 63 in steam generator 14 in order to determine if a previous commitment to monitor and evaluate these unplugged tubes had been implemented during the current outage.

The inspector reviewed randomly selected corrective actions in the Steam Generator and Inservice Inspection Programs to determine if actions related to the programs were being addressed.

b. Findings

No findings of significance were identified.

The inspector determined that PSEG addressed the pre-repair RWST condition in accordance with the ASME Code and concluded that no violation of NRC requirements had occurred. Therefore, URI 50-272/01-07-01 is closed.

1R11 Licensed Operator Requalification

a. Inspection Scope

On November 14, 2002, the inspectors observed a licensed operator simulator training scenario to assess operators' performance and evaluators' critiques. The scenario observed involved operator response to a reduction in main transformer cooling and the implementation of abnormal procedure S2.OP-AB.LOAD-0001(Q), "Rapid Load Reduction." The scenario also involved operator response to a leak in the charging system and the implementation of abnormal procedures S2.OP-AB.RC-0001(Q), "Reactor Coolant System Leak" and S2.OP-AB.RAD-0001, "Abnormal Radiation." The inspectors observed the in-process critiques conducted by the evaluators in the simulator, and reviewed the areas for improvement that were entered into the operator training department critique database.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors reviewed recent operating problems, notifications, system health reports, and maintenance rule (MR) performance criteria to determine whether PSEG had effectively monitored the performance of the Unit 1 CC water system and the Unit 1 pressurizer safety relief valves (included with the reactor coolant system MR data). The inspector reviewed the planned and completed corrective actions for recent system problems involving elevated CC pump vibrations and also for a pressurizer "as found" set pressure test failure (notification 20116997) to ensure that these problems were appropriately addressed. The inspector also reviewed PSEG's assessment of these issues to evaluate the adequacy of the functional failure determinations.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

.1 12 Service Water Header Piping Inspection and WEKO Seal Repair

a. Inspection Scope

The inspectors reviewed selected maintenance activities associated with the inspection and permanent sealing of the 12 SW header. On November 30, 2001, a leak was discovered on the 12 SW header that was repaired with a temporary rubber WEKO seal. NRC review of the operability determination associated with this temporary repair was documented in Section 1R15.2 of Inspection Report 2002-07. The inspectors reviewed the maintenance records and inspection results of the maintenance activities (order 60024893) to inspect this concrete piping in accordance with engineering change authorization (ECA) 80044126, “No. 12 Service Water Header Piping WEKO Seal Installation." The review also verified that plant risk was properly managed during the installation activities.

b. Findings

No findings of significance were identified.

.2 Power Operated Relief Valve 1PR2 Repair

a. Inspection Scope

The inspectors reviewed selected emergent maintenance activities associated with the troubleshooting and repair of Unit 1 power operated relief valve (PORV), 1PR2 and its air operated actuator. The 1PR2 valve lifted, caused a brief depressurization during plant heat-up, and caused the plant to be cooled down for troubleshooting and repairs. The outage control center (OCC) initiated a TARP Team (notification 20119917) that implemented the technical issues process. PSEG attributed the unexpected lifting of 1PR2 to a maintenance technician’s failure to install a required spacer during the completion of order 60023070. PSEG’s root cause analysis of this event was performed under notification 20120466 and order 70028106. The root cause analysis report had not been issued by the end of the inspection period.

The inspectors reviewed the maintenance records and the results of the maintenance activities to repair 1PR2 under orders 60032780 and 60032911. The inspectors reviewed the completed maintenance procedure, SC.IC-PM.RC-0001(Q), “Pressurizer PORV Valve Actuator Maintenance.” The inspectors also interviewed selected engineering and work planning personnel. The inspectors also verified that NRC identified discrepancies associated with the calculations of the valve internal measurements were documented in notification 20122636.

b. Findings

Introduction. The inspectors identified that the records of troubleshooting and repair activities on the 1PR2 valve were incorrect and incomplete. This finding was evaluated and determined to be of very low risk significance (Green), because it did not directly affect the operation of a mitigating system. This finding was a recurrence of a violation (NCV 2001-12-02) that was previously identified in NRC Inspection Report (IR) 2001-12 and indicated that previous attempts to correct this problem were ineffective.

Description. During the review of orders 60032780 and 60032911, the inspectors noted discrepancies between the electronic records of the work orders and the paper records of the work orders. The discrepancies were related to procedures specified to be used versus the procedures actually used. The actual work and troubleshooting records were incomplete and did not document the principal maintenance activities. The inspectors also noted that the 1PR2 air actuator test record was retained by the valve engineering in lieu of being retained as a quality record. PSEG initiated notifications 20125602 and 20125560 to capture these issues in the corrective action program.

Analysis. This finding adversely impacted the inspectors' ability to perform their regulatory oversight function to independently assess the operability of equipment important to safety. The finding affected the Mitigating System Cornerstone reliability objective and was therefore greater than minor. The finding was determined to be very low safety significance (Green) since the 1PR2 has been functioning satisfactorily since the completion of the maintenance and post-maintenance testing. Also, this finding had an aspect of problem identification and resolution, in that it indicated that corrective actions for a previous, similar violation (IR 2002-12) had not been effective.

Enforcement. Technical Specification (TS) 6.10.1.b requires that records and logs of principal maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety be retained for at least five years. Contrary to the above, PSEG failed to maintain complete and adequate records of inspection and maintenance activities performed on the 1PR2. This very low risk violation has been entered in the corrective action program (notification 20091973) and is being treated as the first example of a non-cited violation consistent with the Section VI.A of the NRC's Enforcement Policy: NCV 50-272 and 50-311/02-09-03.

.3 22 Containment Fan Cooling Unit (CFCU)

a. Inspection Scope

The inspectors reviewed selected emergent maintenance activities associated with the troubleshooting and repair of 22 CFCU and its associated flow control valves. These activities were selected for inspection, because following scheduled maintenance, the 22 CFCU began oscillating from 0-2000 gpm when returned to service. Additional aspects of this issue were documented in Sections R15 and R19. Engineering personnel were assembled to implement the technical issues process. The inspectors reviewed the following corrective action and work order documents associated with this issue:

- Notifications 20122677 and 20122736 and order 60033111
- Notifications 20122710 and order 60033240
- Order 60032382

The inspectors reviewed all the maintenance records and results of the maintenance activities provided by PSEG for repairs to the flow controls for the 22 CFCU under orders 60033240, 60033111 and 60032382. The inspectors reviewed the records of the completed procedure used, SH.MD-AP.ZZ-0002(Q), "Maintenance Department Troubleshooting and Repair" for troubleshooting in accordance with order 60033240.

The inspectors verified that an inspector-identified discrepancy associated with PSEG's failure to include the unavailability of the 22 CFCU in the weekly risk assessment (week 99), when the work was carried over from work week 98, was entered into the corrective action process and documented by notification 201220123088.

b. Findings

Introduction. The inspectors identified that the records of troubleshooting and repair activities on the the 22 containment fan cooling unit were incorrect and incomplete. This was the second example of this finding. This finding was evaluated and determined to be of very low risk significance (Green), because it did not directly affect the operation of a mitigating system.

Description. During the review of notifications 20122677, 20122736 and 20122710, and orders 60033111, 60033240 and 60032382, the inspectors noted discrepancies between the electronic records of the work orders and the paper records of the work orders related to procedures used. The inspectors also noted that the records of the actual work performed were incomplete. Some examples of this observation included: records were not found for troubleshooting under order 60033111; records were not found for Temporary Modification (TM) 02-036 that was installed and removed under order 60033240; and records were not found for testing under order 60032382. Neither the electronic nor the paper records provided the documentation of these principal maintenance activities. PSEG documented these issues in the corrective action program.

Analysis. This finding adversely impacted the inspectors' ability to perform their regulatory oversight function to independently assess the operability of equipment important to safety. This finding affected the Mitigating System Cornerstone reliability objective and was therefore greater than minor. The finding was of very low safety significance, since the 22 CFCU had been tested and found operable during post maintenance testing and in service. Also, this finding had an aspect of problem identification and resolution, in that it indicated that corrective actions for a previous, similar violation (IR 2002-12) had not been effective.

Enforcement. Technical Specification 6.10.1.b requires that records and logs of principal maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety be retained for at least five years. Contrary to the above, PSEG failed to maintain complete and adequate records of inspection and maintenance activities performed on the 22 CFCU. This very low risk violation has been entered in the corrective action program and is being treated as the second example of a non-cited violation consistent with Section VI.A of the NRC's Enforcement Policy: NCV 50-272 and 50-311/02-09-03.

.4 Other Emergent Maintenance Activities

a. Inspection Scope

The inspectors reviewed additional selected maintenance activities through direct observation, document review (risk assessment reviews, operating logs, industry operating experience and notifications), and personnel interviews. This review was performed to determine whether PSEG properly assessed and managed the risk, and performed these activities in accordance with applicable TS and work control requirements, including the administrative procedures for managing risk associated with conducting maintenance activities during both on-line and outage conditions. The following activities were reviewed:

- 1A, 1B and 1C EDG maintenance outages during 1R15.
- Unit 1 forced outage activities on November 12, 2002.
- Installation of a bus link on the 2C battery on November 12, 2002.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions

.1 Synchronizing Main Generator to the Grid

a. Inspection Scope

The inspectors observed selected portions of the preparations and synchronization of the main generator to the grid on November 6, following the Unit 1 refueling outage and return to Mode 1. The inspectors verified that the activities were performed in accordance with S1.OP-SO.TRB-0001(Q), "Turbine Generator Startup Operations." The inspectors noted that management oversight was provided by an assistant operations manager and also that identified procedural problems were placed into the corrective actions program (notifications 20120646 and 20120831).

b. Findings

No findings of significance were identified.

.2 Power Operated Relief Valve 1PR2 Lift During Plant Pressurization

a. Inspection Scope

During plant heatup on November 1, 2002, the 1PR2 PORV lost closed indication and reactor coolant system pressure began to lower. Attempts to close the valve manually were unsuccessful and the pressure reduction was terminated by closing the PORV block valve, 1PR7. A transient assessment response plan (TARP) team was assembled. Subsequently, the plant was cooled down and the valve internals were inspected. PSEG determined that a spacer from the internal trim package had not been reinstalled when the 1PR2 was worked on during the outage. The inspectors verified that this issue was entered into the corrective action program (notification 20119917) and a level 1 root cause analysis and a review of the human performance aspects were planned. The inspectors observed and monitored selected portions of the TARP team activities.

b. Findings

No findings of significance were identified.

.3 Manual Reactor Trip of Salem Unit 1 Due to Low S/G Water Level Caused by Feed Pump Runback

a. Inspection Scope

The inspectors reviewed the response to a Unit 1 reactor trip that occurred on November 12, 2002 following the unexpected loss of the 11 main feedwater pump. The 11 main feedwater pump trip was caused by the momentary shorting of an electrical probe to ground during a troubleshooting activity. The inspectors reviewed this event to ensure that the operator response was appropriate and in accordance with operating procedures, mitigating equipment operated properly, and to confirm that PSEG's post-trip review and corrective actions were thorough. The inspectors interviewed operators and operations management, reviewed applicable documentation including operator logs, the TARP report, the post-trip data package, the four-hour non-emergency event report, applicable notifications and attended the post-trip SORC review meeting to ensure that the cause(s) of the event were understood and addressed. Additionally, the inspectors reviewed notification 20122632 to resolve inspector-identified problems associated with the maintenance and implementation of the Trip Hazards Area program.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

.1 Containment Isolation Valve Control Cable Cut

a. Inspection Scope

The inspectors reviewed the operability determination (CROD)-02-009 (notification 20114253) for a control cable for a reactor coolant pump cooling water containment isolation valve (1CC118). Design change activities to replace cable fire wrap resulted in a six-inch longitudinal cut through the outer jacket, copper shielding material, an insulating sheath, an inner protective layer and through one conductor's insulation layer. PSEG's visual inspection of the cut did not find any damage to any conductors. No alarms were received and valve indication was not lost in the control room. PSEG tested and verified circuit continuity of the conductors with a critical safety function. The inspectors verified that compensatory measures were implemented and corrective actions were specified. The inspectors also reviewed order 70027181 that documented the follow-up operability assessment (CRFA) performed in accordance with procedure SH.OP-AP.ZZ-0108, "Operability Assessment and Equipment Control Program."

b. Findings

No findings of significance were identified.

.2 Control Room Ventilation Radiation Monitor 1R1B

a. Inspection Scope

The inspectors reviewed the operability determination (CROD)-02-008 (Notification 20113713) for the control room ventilation radiation monitor spiking into alarm and realigning the control area ventilation (CAV) system. PSEG believed that a faulty radiation detector temperature alarm module was producing noise that resulted in the spurious radiation alarms and CAV system realignment. PSEG performed troubleshooting and determined that the radiation detector and the radiation detector heater (required for environmental qualification) were working properly. The inspectors verified that compensatory measures were implemented and corrective actions were specified. The inspectors also reviewed Order 70027081 that documented the follow-up operability assessment (CRFA) performed in accordance with procedure SH.OP-AP.ZZ-0108, "Operability Assessment and Equipment Control Program."

b. Findings

No findings of significance were identified.

.3 Unit 1 AMSAC

a. Inspection Scope

During a control room tour on November 14, 2002, the inspectors noted that the AMSAC trouble alarm was illuminated. Based on discussions with control room operators, the inspectors noted that the system was inoperable, the condition had been logged and had been entered into the corrective action system (notification 20121636). The inspectors discussed the condition further with operations and engineering personnel to determine whether the AMSAC system had been inoperable when the plant was restarted from the Unit 1 forced outage in November. The inspectors reviewed control room alarms and determined that the AMSAC system was operable during the plant start-up. PSEG initiated notifications 20122925, 20122627 and 20122624 to document that an issue associated with operator awareness of the AMSAC system status during the start-up and also to identify enhancements to the AMSAC alarm response and maintenance procedures.

b. Findings

No findings of significance were identified.

.4 22 Containment Fan Coil Unit

a. Inspection Scope

On November 20 PSEG maintenance personnel performed calibration and testing of the 22 CFCU flow instruments (Section R19). On November 23 while attempting to perform procedure SC.IC-LC.SW-0001(Q), "Containment Fan Coil Unit Service Water Flow Instruments Loop Calibration," in accordance with Order 30069819, control room and maintenance personnel observed 0-2000 g.p.m. flow oscillations with the 22 CFCU in service. The 22 CFCU was removed from service. Unit 2 was in a previously entered (November 19) limiting condition for operation (LCO) for scheduled maintenance on the 22 CFCU. PSEG performed troubleshooting and found that the SW flow could be stabilized with the flow controller in manual control and the flow control valve (22SW223) full open. The oscillations returned when the controller was returned to automatic control. To resolve the inability to control SW flow at the accident flow setpoint, PSEG configured the 22 CFCU in the manual control mode with the 22SW223 valve full open (greater than normal accident flow). The 22 CFCU fans were also configured to only operate at the accident (low) speed. PSEG planned to limit run time on the 22 CFCU to that required for surveillance testing.

PSEG considered the 22 CFCU degraded, but operable with the flow controls in manual in lieu of its normal automatic control mode. The inspectors reviewed the operability determination (CROD)-02-011 (Notification 20122803 and Order 70028270), the regulatory change process determination and the 10 CFR 50.59 screening performed for the degraded condition. The inspectors also observed the SORC meeting that reviewed these documents for safety concerns. The inspector also verified that PSEG implemented administrative controls to declare the 22 CFCU inoperable if the river temperature were to exceed 60°F. The inspectors also reviewed the follow-up operability assessment (CRFA) documented in order 70028270 that was performed in accordance with procedure SH.OP-AP.ZZ-0108, "Operability Assessment and Equipment Control Program."

b. Findings

No findings of significance were identified.

.5 14 Containment Fan Cooling Unit

a. Inspection Scope

On December 22 PSEG personnel attempted to place the 14 CFCU in the high-speed, low-flow mode of operation for valve stroke time testing. The 14 CFCU outlet flow control (accident mode) valve (14SW223) slowly stroked closed and one of the normal flow control valves (14SW57) indicated open (accident position) with no measurable stroke time. Unit 1 was in a previously entered (December 17) LCO for scheduled maintenance on the 14 CFCU. PSEG formed a TARP team to investigate (Notification 20125678). Based on troubleshooting PSEG concluded that the most likely cause of this problem was that a second normal flow control valve (14SW65) was throttled open. To resolve this problem PSEG racked out and removed the control power to the high speed fan breaker and performed testing, which demonstrated that the 14 CFCU was operable but degraded in this configuration. The inspectors reviewed PSEG activities to confirm that the 14 CFCU was operable in the "as left" configuration.

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

a. Inspection Scope

On December 9-13 the inspectors reviewed the outstanding Salem Unit 1 and Unit 2 operator burdens as described by operations procedure, SH.OP-AP.ZZ-0030(Q), “Operator Burden Program.” Additionally, the inspectors reviewed the open operator workarounds, operator concerns, overhead annunciators, control room instrumentation and computer point deficiencies. These items were reviewed to ensure that identified system deficiencies would not prevent operators from properly responding to plant events.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

.1 12 Service Water Header Piping WEKO Seal Installation

a. Inspection Scope

The inspectors reviewed selected portions of a design change (order 80044126) that had modified the 12 SW header piping and installed a WEKO seal to restore the degraded header to its design qualification. The inspectors reviewed the 10 CFR 50.59 screening done for this design change. The inspectors also reviewed Vendor Technical Document (VTD) 325626 (MPR Associates Calculation 2449, “Evaluation of Salem Generating Station Concrete Service Water Pipe Specials”) that provided analysis and established bounding criteria to demonstrate that the repair of the 12 SW header with a double wide WEKO seal and segmented stainless steel cylinder would restore the header piping to its original design criteria. The bounding criteria included: (1) minimum remaining average wall thickness of the unflawed metal; (2) length of the through-wall flaw; (3) limited damage to the concrete coating on the steel pipe; (4) mortar coated steel piping without pre-stressed concrete; and (5) limited deterioration of the longitudinal tie rods. The inspectors verified that the design bases, licensing bases, and performance capability of risk significant systems and components were not degraded by the design change.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors observed the performance of post-maintenance testing (PMT) and/or reviewed documentation for selected risk-significant systems to assess whether the systems met TSs, UFSAR and PSEG procedural requirements. The inspectors assessed whether the testing appropriately demonstrated that the systems were operationally ready and capable of performing their intended safety functions. The following test activities were reviewed:

- Selected maintenance activities associated with the troubleshooting and repair of Unit 1 PORV 1PR2 under order 60032911.

- Selected maintenance activities associated with the troubleshooting and repair of the 1PR2 air operated actuator under order 60032780.

- Calibration of the 22 CFCU loop flow control devices on November 20, 2002, in accordance with Order 30069819 and procedure SC.IC-LC.SW-0001(Q), "Containment Fan Coil Unit (CFCU) Service Water Flow Instruments Loop Calibration." The inspectors also reviewed the pre and post calibration testing that was completed in accordance with procedure S2.IC-SC.SW-0001(Q), "Containment Fan Coil Unit Service Water Inlet/Outlet Flow."

- Scheduled maintenance outages on the 12 chilled water pump and the 12 component cooling water pump during the week of December 15, 2002, and EDG maintenance activities performed during 1R15, following their completion.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

.1 Routine Observations

a. Inspection Scope

The inspectors reviewed the key activities planned and scheduled for the Unit 1 refueling outage (1R15), the 1R15 risk assessment report, and the contingency plans developed for the two reactor coolant system (RCS) mid-loop operating periods and for the removal of the 12 service water header from service. This review was performed to determine whether PSEG appropriately assessed and had planned actions to manage the risk associated with the 1R15 activities. Some of the specific activities reviewed included:

- Plant cooldown data to determine whether the plant cooldown was performed in accordance with TS limits.

- Plant configuration to periodically verify its consistency with the plant Outage Risk Assessment and Management (ORAM) plan, including availability of decay heat removal systems as required.

- Reduced inventory and mid-loop conditions. Reviewed contingency plans for inventory control for RCS at mid-loop with fuel in the reactor vessel. Verified that a temporary level column was installed and that it was periodically monitored to determine the water level in the RCS hot leg and the reactor pressure vessel. Reviewed preparations for steam generator nozzle dam removal including mock-up training. Verified that the containment equipment hatch was secured during reduced inventory operations and that the personnel equipment hatch could be promptly secured.

- Fuel handling operations, including removal and insertion of the fuel bundles and fuel movement within the spent fuel pool. Verified that fuel handling was performed in accordance with plant procedures and that the location of fuel assemblies, including new fuel assemblies, and control elements were tracked from core offload through core reload.

- Selected maintenance activities, including RWST discharge nozzle weld inspection and restoration, 12 SW header outage and internal pipe inspections, and EDG maintenance outages.

- Bare metal visual inspection of the Reactor Pressure Vessel (RPV) head with PSEG personnel. Conducted a visual inspection of the under-RPV area at normal operating temperature and pressure conditions.

- Walkdown of selected areas of the containment and pressurizer cubicle during closeout activities and prior to reactor startup to identify debris that could affect the performance of the containment emergency sump. Identified some minor deficiencies to PSEG outage management personnel for resolution following this walkdown.

- Plant restoration, including control of mode changes, start-up and power ascension activities.

b. Findings

A finding (discussed in Section R23) was identified involving the failure to properly evaluate a temporary modification to the 11 service water header while the 12 service water header was removed from service. No other findings of significance were identified.

.2 One Shutdown Cooling Loop Inoperable and less than 23 Feet of Water Above the Fuel

a. Inspection Scope

On October 25 the inspectors noted a late log entry documenting entry into TS Action Statement (TSAS) 3.9.8.2. Entry into this TSAS was required when less than two RHR loops are operable with the reactor cavity water level less than 23 feet above the top of the fuel in the reactor vessel. The inspectors reviewed selected procedures, risk and contingency planning documents, control room logs, notification 20118564, order 70027847 and discussed the event with PSEG operations, outage management, risk assessment and licensing personnel to evaluate the adequacy of PSEG's review of this event.

b. Findings

Introduction. PSEG removed the 11 component cooling water (CCW) pump room cooler fan from service at conditions not permitted by TS (i.e., with refueling cavity level less than 23 feet). This finding was determined to be of very low risk significance (Green), because during the event the 11 CCW pump remained available and functional, and therefore did not directly affect the operation of a mitigating system.

Description. Technical Specification Action Statement 3.9.8.2 requires that two operable RHR loops be maintained when the reactor cavity water level is less than 23 feet above the top of the active fuel. At 2:23 a.m. on October 25, 2002, the 1C vital bus was de-energized with the refueling cavity drained down below a level of 23 feet of water above the fuel in the reactor vessel. This de-energized the fan motor of the 11 CCW pump room cooler that was required to support operability of the 11 CCW pump (one of two CCW pumps required to maintain two RHR loops operable). This oversight was identified a few hours later by an oncoming operating crew.

Also, PSEG had not implemented the required compensatory measures prior to de-energizing the fan room cooler. These actions would have included, running the available (12) room cooler, propping open the 11 CCW pump room door, tagging the auxiliary feedwater pumps out of service, stopping the safety injection and containment spray pumps, ensuring service water temperature is below 90°F, and monitoring atmospheric temperature. PSEG evaluated this issue and identified human performance, procedure and administrative controls, supervisory oversight and human performance as contributing factors to this event. Additionally, the operating procedures did not cover the 11 CCW pump and room cooler within 1C vital bus de-energizing guidance. Inadequate scheduling and coordination of major outage events and the failure to identify required compensatory measures were also identified as contributors to this event.

Analysis. This finding affected the configuration control attribute of the availability objective of the Mitigating System Cornerstone since it involved the failure to adequately control outage activities and affected the operability of required decay removal systems while shutdown and was therefore more than minor. The finding was reviewed by NRC Senior Reactor Analysts from Region I and NRR and determined to be of very low safety significance since the 11 CCW pump was able to function for the period of time that the room cooling fan was removed from service without the necessary compensatory measures. Therefore, the 11 CCW pump remained available and functional.

Enforcement. Technical Specification 6.8.1.a requires that written procedures shall be established and implemented for activities in Appendix "A" of Regulatory Guide (RG) 1.33. Regulatory Guide 1.33 requires that procedures be developed to perform maintenance on safety related systems. PSEG failed to establish and implement adequate procedures prior to conducting maintenance that removed the 11 CCW pump room cooler from service. This very low risk violation has been entered in the corrective action program (notification 20118564) and is being treated as a non-cited violation consistent with the Section VI.A of the NRC's Enforcement Policy: NCV 50-272 and 50-311/02-09-04.

1R22 Surveillance Testing

.1 Routine Testing

a. Inspection Scope

The inspectors reviewed the test results for selected risk significant components systems to assess whether the components met TS, Updated Final Safety Analysis Report, and PSEG procedural requirements. The inspectors assessed whether the testing appropriately demonstrated that the components were operationally ready and capable of performing their intended safety functions. The following tests and activities were reviewed:

- S1.OP-ST.CH-0002(Q), "Inservice Testing - 12 Chilled Water Pump"
- S1.OP-ST.CC-0002(Q), "Inservice Testing - 12 Component Cooling Pump"

b. Findings

No findings of significance were identified.

.2 Containment Air Temperature Surveillance Measurement

a. Inspection Scope

The inspectors interviewed design engineers and reviewed vendor documentation to determine whether the containment integrity design basis accident analysis considered the initial temperature of the containment passive heat sinks. This review was conducted to determine whether PSEG's method for determining the containment average air temperature per TS 4.6.1.5 was consistent with the design basis accident analysis assumptions for initial containment temperature as discussed in Inspection Report 50-272 & 50-311/01-09 (URI 50-272 &50-311/01-09-01).

b. Findings

PSEG demonstrated that the initial containment temperature assumed in the containment integrity design basis analysis considered the initial (i.e. pre-accident) temperature of the containment passive heat sinks. The inspectors concluded that PSEG's method for measuring containment temperature as described in Inspection Report 50-272 & 50-311/01-09 would satisfy design basis accident assumptions. Therefore, no violations of NRC requirements were identified and URI 50-272 & 50-311/01-09-01 is closed.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary modifications (TMs) to assess: (1) the adequacy of the 10 CFR 50.59 screen or evaluation; (2) the installation and removal conditions and instructions; (3) the updating of drawings and procedures; and (4) the expected removal date. The following TMs were inspected:

- 02-037, “Bypass Detector Low Temperature Alarm for Radiation Monitor 2R1B, Channel 1"
- Installation of a Temporary Hose to the 11SW527 Valve

b. Findings

Introduction. The inspectors identified that a temporary modification (hose connection and pump) to the service water system was not properly evaluated. A Green NCV was identified for failure to adequately evaluate a rubber hose that was temporarily attached to the only operable service water header as prescribed by 10 CFR 50, Appendix B, Criterion III, “Design Control.”

Description. The inspectors identified that on October 18, 2002, a temporary rubber hose and air-operated pump were connected to the 11SW527 valve to facilitate draining of leakage from the 12 SW header. The hose was approximately 3 inches in diameter, and manually-operated 11SW527 valve was left in the open position. In this configuration the temporary hose and air-operated pump formed an extension of the 11 SW header pressure boundary and failure of this temporary assembly would have adversely affected the capability of the SW system to supply required safety-related loads. The 12 SW header was out of service for maintenance and reactor core defueling operations were in progress while the temporary assembly was connected.

The inspectors informed operations personnel regarding this concern and reviewed operations procedure, S1.OP-SO.SW-0005, “Service Water System Operation,” and the temporary modification log to determine whether this configuration had been previously analyzed. The inspectors determined that this configuration had been established without performing an adequate engineering evaluation of the potential impact of this temporary assembly on the SW system. Operations personnel implemented interim corrective measures to shut the 11SW527 valve when not actually using the connection to drain the leakage from the 12 SW header and initiated notification 20117389 to enhance the procedural guidance for control and use of temporary assemblies.

Analysis. The inspectors determined that this finding was associated with the evaluation and use of temporary equipment that affected the design control attribute of the capability objective of the Mitigating Systems Cornerstone to maintain an operable service water system, and is therefore greater than minor. If left uncorrected, this finding could have resulted in a more significant safety concern (i.e. the failure of the temporary hose assembly could have challenged the capability of the only operable service water header while reactor core defueling operations were in progress). This finding was evaluated using the Phase I worksheet of the SDP and determined to be of very low risk significance (Green) since the temporary hose assembly remained intact, was installed for a short period of time, and was typically attended by a nuclear equipment operator.

Enforcement. 10 CFR 50, Appendix B, Criterion III, “Design Control,” requires that applicable regulations for structures, systems, and components are properly translated into specifications, procedures and drawings. Contrary to the above, PSEG failed to develop adequate specifications and procedures prior to connection of a temporary hose assembly to the 11 SW header. Because the failure to develop adequate controls for this configuration was determined to be of very low significance and has been entered into the corrective action program (notification 20117389), this violation is being treated as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-272/02-09-05, Failure to Properly Evaluate a Temporary Installation to the 11 Service Water Header.

2. RADIATION SAFETY

Occupation Radiation Safety [OS]

2OS1 Access Control to Radiologically Significant Areas

a. Inspection Scope

During the period October 21-25, 2002, the inspector reviewed exposure significant work areas, high radiation areas, and airborne radioactivity areas in the plant and evaluated associated controls and surveys of these areas to determine if the controls (i.e., surveys, postings, barricades) were acceptable. The primary focus of this inspection was observing and reviewing work activities associated with the Unit 1 refueling outage (1R15). For these areas the inspector reviewed radiological job requirements and attended job briefings to determine if radiological conditions in the work area were adequately communicated to workers through briefings and postings. The inspector also verified radiological controls, radiological job coverage, and contamination controls to ensure the accuracy of surveys and applicable posting and barricade requirements. The inspector obtained this information via: interviews with PSEG personnel; walkdown of systems, structures, and components; and examination of records, procedures, or other pertinent documents. The inspector determined if prescribed radiation work permits (RWPs), and procedure and engineering controls were in place; whether PSEG surveys and postings were complete and accurate; and if air samplers were properly located. The inspector reviewed RWPs used to access these and other high radiation areas to identify the acceptability of work control instructions or control barriers specified. The inspector reviewed electronic pocket dosimeter alarm set points (both integrated dose and dose rate) for conformity with survey indications and plant policy. The controls implemented by PSEG were compared to those required under plant technical specifications (TS 6.12) and 10 CFR 20, Subpart G for control of access to high and locked high radiation areas.

b. Findings

No findings of significance were identified.

2OS2 As Low As Is Reasonably Achievable (ALARA) Planning and Controls

a. Inspection Scope

The inspector reviewed ALARA job evaluations, exposure estimates, and exposure mitigation requirements and compared ALARA plans with the results achieved. A review was performed of the integration of ALARA requirements into work procedures and RWP documents, the accuracy of person-hour estimates and person-hour tracking, and generated shielding requests and their effectiveness in dose rate reduction. The inspector obtained this information via: interviews with PSEG personnel; walkdown of systems, structures, and components; and, examination of records, procedures, or other pertinent documents.

The inspector also reviewed exposure goals established for the Unit 1 refueling outage (1R15). An outage goal of 110 person-rem had been established by PSEG, including the following work activities and their outage exposure goal: reactor maintenance (18.500 rem); primary steam generator work [including eddy current testing] (20.335 rem); reactor coolant pump and motor work (3.460 rem); and, in-service inspection (7.700 rem). By day 14 of the outage, outage exposures exceeded 116 person-rem. The primary reason for exceeding the outage goal identified by PSEG was higher than anticipated area dose rates as the result of a shutdown crud burst and the subsequent inability to remove the radioactive material from the primary coolant in sufficient quantity prior to the start of outage work.

Since the 1999 Unit 1 refueling outage (1R13), this is the third time greater than anticipated area dose rates have been created following a shutdown crud burst and subsequent primary coolant clean-up. Similar issues also arose during the 2000 Unit 2 refueling outage (2R11). Corrective actions taken after both of these previous outages proved insufficient to prevent a recurrence during 1R15.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation

a. Inspection Scope

The inspector reviewed field instrumentation utilized by radiation protection technicians and plant workers to measure radioactivity, including portable field survey instruments, friskers, portal monitors and small article monitors. The inspector reviewed selected radiation protection instruments observed in the radiologically controlled area (RCA), specifically verification of proper function and certification of appropriate source checks for these instruments which were utilized to ensure that occupational exposures are maintained in accordance with 10 CFR 20.1201. The inspector obtained this information via: interviews with PSEG personnel; walkdown of systems, structures, and components; and examination of records, procedures, or other pertinent documents.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Physical Protection [PP]

3PP3 Response to Contingency Events

a. Inspection Scope

The inspectors reviewed the status of security operations and assessed implementation of the protective measures in place as a result of the current, elevated threat environment.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator Verification

.1 Public Radiation Safety Cornerstone

a. Inspection Scope

The inspector reviewed a listing of licensee event reports for the period January 1, 2002 through October 21, 2002 for issues related to the public radiation safety performance indicator, which measures radiological effluent release occurrences per site that exceed 1.5 milli-rem per quarter (mrem/qtr) whole body or 5 mrem/qtr organ dose for liquid effluents; or 5 mrads/qtr gamma air dose, 10 mrads/qtr beta air dose; or 7.5 mrems/qtr organ doses from I-131, I-133, H-3 and particulates for gaseous effluents.

b. Findings

No findings of significance were identified.

.2 Emergency Preparedness

a. Inspection Scope

The inspector reviewed PSEG's procedure for developing the data for the emergency preparedness PIs which are: (1) Drill and Exercise Performance, (2) Emergency Response Organization Drill Participation and (3) Alert Notification System (ANS) Reliability. The inspector also reviewed PSEG's drill/exercise reports, training records and ANS testing data from the fourth quarter of 2001 to the end of the third quarter of 2002 to verify the accuracy of the reported data. The review was performed in accordance with NRC Inspection Procedure 71151. The acceptance criteria are 10 CFR 50.9 and NEI 99-02, Revision 2, Regulation Assessment Performance Indicator Guideline.

b. Findings

No findings of significance were identified.

.3 Reactor Scram and Unplanned Power Reductions

a. Inspection Scope

The inspectors reviewed the performance indicator (PI) data submitted by PSEG for "Unplanned Scrams per 7000 Critical Hours," "Scrams with a Loss of Normal Heat Removal," and "Unplanned Transients per 7000 Critical Hours" to ensure that the data was consistent with the plant operating histories and with the guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline." The inspectors reviewed the data submitted from the third quarter of 2001 to the third quarter of 2002.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Cross Reference to P&IR Findings Documented Elsewhere

Section 40A5 describes a finding for failure to be able to achieve and maintain a 50 percent concentration of carbon dioxide for 30 minutes by the fire suppression systems for six safety-related areas. The failure of PSEG to identify that modifications to the ventilation system to trip the exhaust fans aggravated this previously identified condition and to implement timely and effective action for the conditions are indicative of potential deficiencies in the licensee's corrective action reviews.

.2 Reactor Safety Cornerstone - Salem Unit 1 Inservice Inspection

a. Inspection Scope

The inspector reviewed a sample of corrective action reports shown in Attachment 1, which identified problems related to ISI issues. The inspector verified that problems were being identified, evaluated, appropriately dispositioned, and entered into the corrective action program.

b. Findings

No findings of significance were identified.

.3 Public Radiation Safety Cornerstone - Salem Unit 1 Auxiliary Building Water Leak

a. Inspection Scope

The inspectors reviewed PSEG activities regarding problem identification and resolution of contaminated water leaks into the Auxiliary Building. The review noted the applicable information as discussed below.

On September 18, 2002, PSEG documented (notification 20114071) the discovery of water leakage through the Unit 1 - 78-foot mechanical penetration room wall. PSEG also noted that workers' shoes coming from the room were contaminated. PSEG took smear and water samples. The measurement results indicated that the source of water was from a radioactive system. There has been a history of non-contaminated water leakage in this area (e.g., notification 20001837 in 1999 and MMIS 971217047 in 1977).

On September 25, 2002, PSEG initiated an evaluation (notification 20114152) to resolve the water leakage. Subsequently, PSEG engineering personnel identified a second leak at a spent fuel pool cooling piping penetration (between the Unit 1 spent fuel building and the auxiliary building) located within the Unit 1 78-foot mechanical penetration room.

On November 20, 2002, PSEG informed the resident inspectors of the leak. PSEG personnel reported that chemical analysis of water from the leak was indicative of the Unit 1 spent fuel pool. On November 29, PSEG began installation of a collection device to capture the leakage from under the spent fuel pool cooling line and direct this water to the contaminated drain and liquid radwaste systems.

On December 9-10, 2002, the resident inspectors and a regional specialist toured the Unit 1 78-foot mechanical penetration room and verified the leak catch device under the spent fuel pool cooling water return pipe. The inspectors also toured Unit 1 64-foot switchgear room and noted that there was evidence of five (5) water leaks along the wall in the room. The leaks appeared to be long established with the exception of one (Sample 7). PSEG took five samples and measured for boron, tritium, and gamma analyses. The analytical results of the Sample No. 7 indicated that the source of water was from a radioactive system. Analytical results of the other four (4) samples suggested that these were the results of uncontaminated ground water intrusion. On December 9 PSEG assigned a full-time team and developed an action plan to address the leaks. Two additional notifications (20123998 and 20120815) were drafted to document the corrective actions.

On January 2 and 3, 2003, the inspectors reviewed analytical data, including water samples from seven (7) on-site environmental test locations. The analytical results for tritium, fission, and activated gamma emitters were well below the required lower limits of detection (LLDs) listed in the Offsite Dose Calculation Manual (ODCM). The inspectors attended PSEG's meetings to observe their discussions of (1) soil and water sampling, (2) drilling of permanent deep sampling wells, (3) spent fuel pool water make-up rate, (4) integrity of the fuel transfer canal, (5) sampling the water at the bottom of spent fuel pool to track iodine-131, and (6) monitoring for spent fuel pool water leaks.

b. Findings

No findings of significance were identified at the time of this inspection. At the conclusion of the period the inspectors were unable to determine whether PSEG met all ODCM and 10 CFR 20 effluent release requirements since the environmental sampling activities had not been completed. This issue will remain unresolved pending completion and assessment of the planned environmental monitoring activities (**URI 50-272/02-09-06**).

.4 Unit 2 Residual Heat Removal System Water-Hammer

a. Inspection Scope

An inspection of problem identification and resolution for a selected issue was performed to review the effectiveness of actions in identifying the problem and the implementation of the follow-up corrective actions. The item selected for this review was related to notifications 20099566, 20104986, and 20110575 that documented a water-hammer event during the start of RHR pumps 21 and 22 for testing, and the troubleshooting efforts to determine the cause. The inspection included the review of the troubleshooting efforts, engineering analyses and evaluations, the root cause determination, the corrective action plan, and design modification and post-modification testing following the installation of additional RHR system vents in May 2002. Also, the inspector performed a walkdown of the accessible portions of the RHR system, and reviewed RHR system fill and vent procedure, and reviewed the design and licensing basis for the RHR system.

The inspector did not identify an operability concern with the water hammer events but noted that PSEG's initial efforts to understand and resolve this problem did not appear timely. The initial water-hammer event was identified before the start-up from the Unit 2 refueling outage in May 2002, and the cause was attributed to a check valve slamming noise. Based on the document review and interviews, the inspector concluded that PSEG troubleshooting activities for this problem were delayed until August 2002 (notification 20110575). The inspector noted that the eventual investigation of this problem appeared to be better focused and thorough.

b. Findings

No significant findings were identified.

.5 Human Performance Improvement

a. Inspection Scope

During the June 2001 assessment meeting between the NRC and PSEG, PSEG senior management indicated that a group had been formed to initiate a human performance improvement program. Due to continuing human performance issues at Salem, the inspectors selected this improvement program for review of measurable performance changes regarding the identification and resolution of problems.

The inspectors found that the improvement program described during the 2001 meeting had not been maintained. Also, in the summer of 2002, an industry peer review identified that an integrated and visible approach to improving human performance was not evident at the site. In October 2002 PSEG assigned a new human performance manager and began development of a new human performance program initiative. The inspectors discussed this initiative with the human performance manager and reviewed draft action plans for program implementation. The initial implementation has commenced through the communication and training of senior and mid-level managers on the initiative and tools for implementation. Performance indicators to measure human performance improvement are being developed and populated with data. PSEG indicated that these performance indicators would provide a meaningful measure of performance by the end of 2003. The inspectors determined that it was premature to determine the effectiveness of this program.

b. Findings

No significant findings were identified.

4OA3 Event Followup

.1 (Closed) LER 50-311/02-002-00: Containment Internal Pressure Not Maintained Within Technical Specification Limits

On April 20, 2002, PSEG discovered that the instrumentation used to monitor the containment internal pressure was reading one-half of the actual containment pressure. This lower indicated pressure resulted in operation where the actual containment internal pressure exceeded the 0.3 psig TS 3.6.1.4 limit. The problem resulted from the installation of an incorrect part as an equivalent replacement for an instrumentation module. PSEG's planned and completed corrective actions included repair of the instrument, review of the release calculation used in the Annual Radioactive Effluents Report, review for a similar problem at Unit 1 and entry of this problem into the corrective action program to evaluate the programmatic problems that led to this event. No new findings were identified in the inspector's review. This finding constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. PSEG documented the problem in notification 20097451. This LER is closed.

.2 (Closed) LER 50-272/02-005-00: Unexpected Auto-Start of Turbine Driven Auxiliary Feedwater Pump at Start of Refueling Outage

On October 10, 2002, during the scheduled manual trip to start the 1R15 refueling outage, an unexpected automatic start of the 13 auxiliary feedwater pump occurred. Operators responded properly to the event. This event resulted from the previous adjustment of the steam generator low-low setpoint that was performed in response to a generic concern (discussed in Inspection Report 50-272 & 50-311/02-03). PSEG's planned and completed corrective actions included evaluation of whether further setpoint changes could be implemented to preclude this type of event and a review to determine whether this type of event can be defined as expected. The LER was reviewed by the inspectors and no findings of significance were identified. PSEG documented this event in notification 20116128. This LER is closed.

.3 (Closed) LER 50-272/02-007: Core Alterations Performed Without Direct Communications

On October 16, 2002, while lifting the upper internals from reactor vessel, PSEG failed to establish direct communications between the control room and the refueling station as required by TS 3.9.5. PSEG's planned and completed corrective actions included development of a temporary standing order to clarify roles and responsibilities for the refueling and operating crews, and procedural enhancements. No new findings were identified in the inspector's review. This finding constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. PSEG documented the problem in notification 20116936. This LER is closed.

4OA5 Other Activities

.1 TI 2515/150 - Reactor Pressure Vessel Head (RPV) and Vessel Head Penetration Nozzles (NRC Bulletin 2002-02)

a. Inspection Scope

The inspectors reviewed PSEG's activities to detect circumferential cracking of RPV head penetration nozzles in response to NRC Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," as specified by Temporary Instruction (TI) 2515/150. The activities included interviews with analyst personnel and other technical staff, reviews of qualification records, procedures, and observations of selected video tape and pictures of the reactor vessel closure head visual examination. The inspectors also reviewed the susceptibility calculation to verify that appropriate plant-specific information was used as input. In accordance with TI 2515/150, inspectors verified that deficiencies and discrepancies associated with the RCS pressure boundary or the examination process was identified and that they were placed in PSEG's corrective action process.

b. Findings

No findings of significance were identified and the specific reporting requirements of TI 2515/150 are documented in Attachment 1.

.2 TI 2515/148, Revision 1, Appendix A - Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures

a. Inspection Scope

An audit of PSEG's performance of the interim compensatory measures imposed by the NRC's Order Modifying License, issued February 25, 2002 was completed in accordance with the specifications of NRC Inspection Manual Temporary Instruction (TI) 2515/148, Revision 1, Appendix A, dated September 13, 2002.

b. Findings

No findings of significance were identified.

.3 (Closed) URI 50-272; 50-311/02-07-01: Failure to maintain the Fire Protection Program as described in the FSAR and approved in the SERs.

Introduction. PSEG did not properly maintain room isolation barriers and improperly implemented a modification to the switchgear penetration area ventilation system, both of which caused an existing fire protection concern on carbon dioxide (CO_2) concentration to be exacerbated. This finding (Green NCV) represents the completion of an unresolved item identified in Inspection Report 2002-07 regarding the automatic fire suppression system in six safety-related electrical areas addressed by the fire protection program.

Description. During the 1999 triennial fire protection inspection (NRC Inspection Report 50-272&311/99-10), the inspectors identified a White finding involving the initial testing of the 4160V switchgear room and lower electrical penetration area CO_2 fire suppression systems. When initially tested in 1974 (Unit 1) and 1979 (Unit 2), the systems failed to achieve the design concentration of 50 percent CO_2. The inspectors determined that the plant condition did not meet the requirements of License Conditions 2.C.5 (Unit 1) and 2.C.10 (Unit 2), i.e., the fire protection program. The CO_2 systems as described by PSEG in the FSAR and approved by NRC specify a 50 percent CO_2 concentration to be maintained for 30 minutes.

Following this finding, PSEG initially attempted to replace the CO_2 system with a water-based automatic sprinkler system. This plan was abandoned due to floor drain system limitations. In April 2002 PSEG determined that returning the CO_2 system to fully operable status would be a better alternative.

PSEG performed tracer gas testing in May 2002 to support re-analysis of the CO_2 systems and to resolve issues associated with commitments for CO_2 retention in fire areas at Salem. The test results predicted achievement of approximately 45 percent initial concentrations, which would dissipate to 18 to 28 per cent within 20 minutes.

PSEG identified that the majority of the leakage from the rooms was through the CO2 isolation dampers and the fire door seals. PSEG subsequently determined that the dampers used were backdraft dampers, and therefore improperly utilized for isolation in the switchgear and penetration area ventilation system. PSEG also determined that the five year damper seal replacements recommended by the damper manufacturer had never been done.

The CO2 system design called for the ventilation system fans to trip on a CO2 discharge. The initial ventilation system design had the supply fans continuing to operate after a CO2 discharge, but the exhaust fans tripped. Between 1994 and 1996 PSEG installed engineering changes 1-EC-3377 and 2-EG-3298 that permitted the exhaust fans to continue to operate after a CO2 discharge, thereby further degrading the ability of the CO2 system to achieve and maintain a 50 percent CO2 concentration for 30 minutes.

Analysis. The inspector determined that this finding adversely impacted fire suppression equipment capability, affecting the design control attribute of the capability objective of the Mitigating Systems Cornerstone, and therefore is greater than minor.

The finding was evaluated using Inspection Manual Chapter (IMC) 0609, Appendix F. The finding passed the Phase I screening criteria, since it affected either manual or automatic suppression, depending upon the room.

For the phase 2 evaluation, the inspector developed fire scenarios based on the switchgear units in the areas of concern. The IPEEE fire scenarios were used as the starting point. Since the areas had been the subject of impairments and had fire watch patrols, the transient combustible scenario was not imposed. In addition, the non-propagation fire scenarios for the switchgear fires were assumed to become propagation scenarios, due to the degraded gaseous suppression systems. The most limiting fire scenarios were those which led to a transient with loss of power conversion system, and disabled an auxiliary feedwater pump and a power operated relief valve. The ignition frequencies for these scenarios were summed, and the fire mitigation factors applied. The factors gave full credit for the fire brigade. Existing electrical raceway fire wrap was credited during scenario development by not imposing fire damage to cables which were wrapped. The resulting fire mitigation frequency corresponds to Row D of the risk estimation matrix (Table 5.6 in Appendix F of IMC 0609). The mitigating system capability rating for the remaining auxiliary feedwater trains (3) resulted in an overall risk characterization of Green.

Also, this finding had an aspect of problem identification and resolution, in that ineffective problem evaluation existed regarding the preventive maintenance and modifications on the affected equipment.

Enforcement. License Conditions 2.C.5 (Unit 1) and 2.C.10 (Unit 2) require PSEG to implement and maintain in effect all provisions of the fire protection program as approved in the SERs. Contrary to the above, PSEG failed to properly maintain room isolation dampers and improperly implemented a modification to the switchgear and penetration area ventilation system that resulted in the inability of the carbon dioxide fire suppression systems for six safety-related areas to maintain the design concentration for the specified time period. This self-revealing violation of very low safety significance is not being cited since it meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCV.

4OA6 Management Meetings

a. Exit Meeting Summary

On January 16, 2003, the inspectors presented their overall findings to members of PSEG management led by Mr. Lon Waldinger. PSEG management stated that none of the information reviewed by the inspectors was considered proprietary.

b. PSEG/NRC Management Meeting

On December 17 and 18, 2002, the NRC Region I Deputy Regional Administrator and the Region I DRP Division Director toured Salem Station and met with PSEG management to discuss current plant performance issues.

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

a. Key Points of Contact

C. Banner, EP Supervisor
D. Burgin, EP Manager
H. Berrick, Licensing Engineer
T. Cellmer, Radiation Protection Manager
C. Conner, NDE Engineer
P. Fabian, Steam Generator Engineer
V. Fregonese, Manager Design Engineering
M. Hassler, Radiation Protection Operations Superintendent - Salem
H. Malikowski, Materials Engineering
J. Nagle, Supervisor Licensing
T. Neufang, ALARA Supervisor - Salem
T. Oliveri, NDE/ISI Inspector
R. Schmidt, Materials Engineering
B. Sebastian, ALARA and Support Superintendent
W. Treston, Supervisor ISI
V. Zabielski, Steam Generator Group Manager

b. List of Items Opened, Closed, and Discussed

Opened

50-272&311/02-09-01	URI	Submerged safety-related electrical cables appropriate corrective actions. (Section R06)
50-272/02-09-06	URI	Salem Unit 1 spent fuel pool water leak. (Section 4OA2.3)

Opened/Closed

50-272/02-09-02	NCV	Failure to properly test the 12 component cooling heat exchanger. (Section R07)
50-272&311/02-09-03	NCV	PSEG failed to maintain complete and adequate maintenance records. (Section R13)
50-272&311/02-09-04	NCV	Shutdown cooling loop inoperable and less than 3 feet of water above the fuel. (Section R20)
50-272/02-09-05	NCV	Failure to properly evaluate a temporary installation to the 11 service water header. (Section R23)

Closed

50-272/01-07-01	URI	Inservice Inspection Activities. (Section R08)
50-272&311/01-09-01	URI	Containment air temperature surveillance measurement. (Section R22)
50-272&311/02-07-01	URI	Failure to maintain the fire protection program as described in the FSAR and approved in the SERS. (Section OA5.3)
50-311/02-02-00	LER	Containment internal pressure not maintained within technical specification limits. (Section OA3.1)
50-272/02-05-00	LER	Unexpected auto-start of the turbine driven auxiliary feedwater pump at start of refueling outage. (Section OA3.2)
50-272/02-07-00	LER	Core alterations performed without direct communications. (Section OA3.3)

c. List of Documents Reviewed

In addition to the documents identified in the body of this report, the inspectors reviewed the following documents and records:

Calculation #S-C-RC-MDC-1928, Rev 0, Determination of Effective Degradation Years (EDY) at RFO 1R15 (Salem Unit 1) and 2R13 (Salem Unit 2).
SH.RA-IS.ZZ-0005(Q), Rev 1, VT-2 Visual Examination of Nuclear Class 1, 2 and 3 Systems
SC.RA-IS.RC-0001(Q), Rev 0, Vessel Head Penetration Examination
Drawing E 233-048, Closure Head Assembly for 173" ID Reactor.
Video tape and still photographs of Bare metal inspection and selected RV head nozzles.
NC.NM-AP.22-0004(Q) NDE Inspector vision tests
SH.MD-AS.22-0001(Q) NDE Certificates of Qualification
Reactor power, RCS Flow and RCS temperature data collected by engineering
LR-N02-0297, Response to NRC Bulletin 2002-02, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs Salem Generating Station Units 1 and 2. September 06, 2002.
PSEG Technical Specification 6.9.1.5 Annual Reports Salem and Hope Creek Generating Stations Docket Nos. 50-272, 50-311, and 50-354 dated February 26, 2002
Engineering Evaluation No. S-1-RC-MEE-1509 Rev 0 - 1R14 Steam Generator Tubing Operational Assessment for Cycle 15
Engineering Evaluation No. S-1-RC-MEE-1507 Rev 0 - Salem 1R14 Steam Generator Tubing Condition Monitoring Assessment
Engineering Evaluation No. S-1-RC-MEE-1691 Rev 0 - 1R15 Steam Generator Degradation Assessment
Engineering Evaluation No. S-1-RC-MEE-1508 Rev 0 - 1R14 Steam Generator Tubing Degradation Assessment.

S1.SG-ST.RCE-0001(Q)-Rev 4 Steam Generator Eddy Current Examination
54-ISI-400-11 Revision August 27, 2000 - Framatome Technologies Multi-Frequency Eddy Current Examination of Tubing
Examination Technique Specification Sheet #1 Rev 3 - Bobbin Probe Examination
Examination Technique Specification Sheet #2 Rev 0 - Rotating Probe Examination (115/+Point/080HF)
Examination Technique Specification Sheet #3 Rev 0 - Dual Coil Rotating Probe Examination (+Point MR/HF) U-bend
Examination Technique Specification Sheet #4 Rev 1 - Single Coil Rotating Probe Examination (+Point) U-bend.
6875 by 040 EPRI, ASME, Wear Cal Standard as built drawing - 6016623 B-0
6875 by 040 EPRI, ASME, Wear Cal Standard as built drawing - 6016624 B-0
6875 by 040 EPRI, ASME, Wear Cal Standard as built drawing - 6016625 B-0
6875 by 040 EPRI, ASME, Wear Cal Standard as built drawing - 6016626 B-0
6875 by 040 EPRI, ASME, Wear Cal Standard as built drawing - 6016627 B-0
6875 by 040 EPRI, ASME, Wear Cal Standard as built drawing - 6016628 B-0
6875 by 040 EPRI, ASME, Wear Cal Standard as built drawing - 6016629 B-0
6875 by 040 EPRI, ASME, Wear Cal Standard as built drawing - 6016630 B-0
Radiographic Examination Record Order 600032565
02RF Examination Summary Record 191000 - Integrally welded supports to reactor coolant pump 11 11-PMP-1LG
02RF Examination Summary Record 191100 - Integrally welded supports to reactor coolant pump 11 11-PMP-2LG
02RF Examination Summary Record 221400 - Main Steam System Component 34-MS-2141-1PL-1
02RF Examination Summary Record 221500 - Main Steam System Component 34-MS-2141-1PL-2
02RF Examination Summary Record 221600 - Main Steam System Component 34-MS-2141-1LP-3 thru 6
02RF Examination Summary Record 222000 - Main Steam System Component 34-MS-2141-1PL-7 thru 10
02RF Examination Summary Record 222210 - Main Steam System Component 34-MS-2141-1PL-11
02RF Examination Summary Record 222215 - Main Steam System Component 34-MS-2141-1PL-12
02RF Examination Summary Record 148200 - Safety Injection System Component 2-SJ-1137-13
02RF Examination Summary Record 148300 - Safety Injection System Component 2-SJ-1137-14
02RF Examination Summary Record 148400 - Safety Injection System Component 2-SJ-1137-15
02RF Examination Summary Record 148500 - Safety Injection System Component 2-SJ-1137-16
02RF Examination Summary Record 148900 - Safety Injection System Component 2-SJ-1137-20
02RF Examination Summary Record 005310 - Reactor Pressure Vessel Closure Head Component 1-RPV-NUTS 1-54
Corrective Actions: 20102540, 20097621, 20098121,20099595, 20096101, 20096437

Maintenance of Emergency Preparedness Performance Indicator (PI) Data (NC.EP-DG.ZZ-0001(Z) -Rev 03)

Notifications and Orders related to the Water-hammer event:

20099566, 20099608, 2010264720104986, 20108933, 20110575, 20111010, 20111212, 20113051, 20113361, 20115277, 20114030, and 20113054.

Procedures

Filling and Venting Procedure for RHR: S1.OP-SO.RHR-0003(Q), Rev. 12.
Water-hammer Action Plan, Attachment 5 to Procedure NC.PF-AP.ZZ-0082(Z)

Engineering Evaluations and related Documents

RHR Water-hammer Issue Update, dated September 6, 2002.
Level 2 Evaluation RHR Water-hammer.
Event Time Line 04/05/02 through 11/05/02.

Drawings:
205350-SIMP, Rev. 02, ECCS- Simplified P&ID,
205332-SIMP, Rev. 01, RH R - Simplified P&ID
RH - 2-2, Rev. 11, Aux Bld RHR & Safety Injection P&ID for Elv. 45', 55', and 64'
RH - 2-3, Rev. 10, Reactor Containment RHR & SI P&ID for Elv. 78' 0"

d. List of Acronyms

ALARA	As Low As Is Reasonably Achievable
ANS	Alert and Notification System
ASME	American Society of Mechanical Engineers
CAV	Control Area Ventilation
CC	Component Cooling
CCW	Component Cooling Water
CFCU	Containment Fan Cooling Unit
CFR	Code of Federal Regulations
CO2	Carbon Dioxide
CY	Calendar Year
ECA	Engineering Change Authorization
EDGs	Emergency Diesel Generators
EDY	Effective Degradation Years
EFPY	Effective Full Power Years
EPRI	Electric Power Research Institute
ICMs	Interim Compensatory Measures
IR	Inspection Report
ISI	Inservice Inspection
LCO	Limiting Condition for Operation
LLDs	Lower Limits of Detection
MR	Maintenance Rule
NCV	Non-Cited Violation

NDE	Non-Destructive Examination
NRC	Nuclear Regulatory Commission
OCC	Outage Control Center
ODCM	Offsite Dose Calculation Manual
ORAM	Outage Risk Assessment and Management
PARS	Publicly Available Records
PI	Performance Indicator
PMT	Post-Maintenance Testing
PORV	Power Operated Relief Valve
PSEG	Public Service Electric Gas
PWSCC	Primary Water Stress Corrosion Cracking
RCA	Radiologically Controlled Area
RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RPV	Reactor Pressure Vessel
RV	Reactor Vessel
RWP	Radiation Work Permit
RWST	Refueling Water Storage Tank
SDP	Significance Determination Process
SW	Service Water
TARP	Transient Assessment Response Plan
TI	Temporary Instruction
TM	Temporary Modification
TS	Technical Specifications
TSAS	Technical Specification Action Statement
URI	Unresolved Item
VTD	Vendor Technical Document

e. <u>TI 2515/150 - Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles Reporting Requirements</u>

a.1. Was the examination performed by qualified and knowledgeable personnel?

The examination was performed by qualified and knowledgeable personnel. The inspectors found the use of VT-2 certifications including required visual examination for utilized personnel. The inspection technique utilized for bare metal visual examination was as described in the licensee's Bulletin 2002-02 response, dated 6 September 2002.

a.2. Was the examination performed in accordance with approved procedures?

The visual examination was in accordance with approved and adequate procedures.

a.3. Was the examination able to identify, disposition, and resolve deficiencies?

The examination was adequate to identify, disposition and resolve deficiencies.

a.4. Was the examination capable of identifying the PWSCC phenomenon described in the bulletin?

The examination performed was capable of identifying the PWSCC phenomenon described in the Bulletin 2001-01.

b. What was the condition of the reactor vessel head?

The general condition of the Reactor Vessel (RV) head was clean bare metal with some localized grit or fibrous debris on the uphill side of several nozzles. This debris appeared to be a mixture of inert foreign material/dirt and did not contain any evidence of boric acid. The insulation configuration provides relatively easy access for visual examination. No significant visual obstructions were encountered during the bare metal inspection.

c. Could small boron deposits, as described in the Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," be identified and characterized?

Small boron deposits, as described in Bulletin 2001-01, could be identified and characterized by the visual examination technique used. None were found during this visual inspection.

d. What material deficiencies were identified that required repair?

No material deficiencies associated with concerns described in Bulletin 2001-01 or 2002-02 were found.

e. What if any, significant items that could impede effective examination?

No significant items were identified that could impede effective examination.

TI 2515/150, Section 04.05 d, requires that inspectors report lower-level issues concerning data collection and analysis, and issues deemed to be significant to the phenomenon described in Bulletin. The inspector found the licensee calculation method was identical to what is provided in Appendix C of TI 2515/150. However, several observations were made regarding the potential for variations in the inputs for a specific plant calculation of effective degradation years (EDY). These insights identified by the inspector are provided for information below.

- The licensee's calculation for EDY for the Salem units does not include uncertainty for the unit Effective Full Power Years (EFPY) or RV head temperatures. The licensee and inspectors found no evidence that other plants have utilized input parameter uncertainty for the relative ranking determination.

- The Salem calculation for EDY utilized reactor thermal power data from PSEG fuels which was demonstrated to be more accurate and provides a more conservative result for the Salem units than the generator electric output data used by MRP-44.

- The Salem Reactor Vessel head closure temperatures were calculated by Westinghouse under the WOG program "Technical Support of Generic Letter 97-01, Response for RV Head Penetration Alloy 600 PWSCC." The licensee verified the plant specific inputs utilized remained current before using the vendor calculated head temperatures in the susceptibility ranking calculation. The inspector found that the licensee does not have the information to perform a technical comparison of the method utilized by the WOG to determine RV head temperatures with the method utilized to obtain the reference plant RV head temperature of 600 Deg F in the industry susceptibility model.