U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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Report Nos. 50-272/84-15
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Docket Nos. 50-272
50-311

License Nos. DPR-70
DPR-75

Licensee: Public Service Electric and Gas Company

80 Park Plaza

Newark, New Jersey 07101

Facility Name: Salem Nuclear Generating Station - Units 1 and 2

Inspection At: Hancocks Bridge, New Jersey

Inspection Conducted: April 12, 1984 - May 8, 1984

Inspectors: Beverly Hillman For 6/4/84
J. C. Linville, Senior Resident Inspector date

Beverly Hillman For 6/4/84
R. J. Summers, Resident Inspector date

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J. H. Raval, Reactor Engineer date

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Approved By: 6/5/84
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Section No. 2B, Projects Branch No. 2, DPRP

Inspection Summary:
Inspections on April 12, 1984 - May 8, 1984 (Combined Report Numbers 50-272/84-15 and 50-311/84-15)
Areas Inspected: Routine inspections of plant operations including: status of previous inspection items, review of periodic and special reports, licensee event report review, operational safety verification, surveillance observations, maintenance observations, operating events, strike plan review, allegation followup, and the feedwater hammer event of April 6, 1984. The inspection involved 190 inspector hours by the resident NRC inspectors and 20 hours by two region based inspectors.

Results: There were three violations involving failure to follow procedures for feedwater system cleanup strainer operation (paragraph 11) and review of reactor trips (paragraph 11), failure to take corrective action to ensure restoration of rod position indication and timely testing of diesel generators following a loss of 2B vital bus (paragraph 4), and failure to develop a complete and accurate MEL based on observed misclassifications (paragraph 7). Other problems included the failure of the stator welds on No. 23 Containment Fan Cooling Unit, a water hammer in No. 23 feedwater line, difficulty in measuring the force required to trip the Reactor Trip Breakers, and an apparent lack of under-standing of the requirement to maintain the Boron Injection Tank recirculation flow path to maintain it in an operable condition.

DETAILS

1. Persons Contacted

   Within this report period, interviews and discussions were conducted with members of licensee management and staff as necessary to support inspection activity.

2. Status of Previous Inspection Items

   (Closed) Inspector Followup Item (272/84-08-01) The inspector reviewed revised Report RERR-15 which contained the fourth quarter 1983 effluent data that had been omitted from earlier Report RERR-15I.

   (Closed) Violation (311/82-28-01) This violation involved a tagging error which resulted in an inoperable No. 23 auxiliary feedwater pump due to a failure to perform an independent verification. The licensee does not consider necessary any changes to the administrative program for tagging. Continuing inspector concerns in this area are being tracked under more recent open item 311/84-13-02. Therefore, this item is closed for administrative purposes.

   (Closed) Violation (311/82-05-01) This violation involved failure to establish fire watches at open fire penetrations. In response to this violation, the licensee established a roving fire watch program. During inspection 50-311/84-13, the inspector reviewed the records of roving fire watches and verified that they are monitoring open fire barrier penetrations.

   (Closed) Violation (311/83-13-02) This violation involved a failure to make timely reports required by 10 CFR 50.71. The inspector verified that the licensee revised AP-6, Incident Report and Reportable Occurrence Program, to clarify reporting requirements, and assigned a dedicated individual as the LER coordinator as indicated in the response. The inspector also noted that AP-6 has not yet been revised to be consistent with the 10 CFR 50.72 and 10 CFR 50.73 requirements which became effective January 1, 1984. The licensee stated that the revision is in progress and the inspector noted that the licensed operators have been trained in accordance with the new requirements. The inspector will review the new revision to AP-6 when it is issued.

   (Closed) Violation (311/83-15-06) This violation involved a failure to establish containment integrity in the required time with less than the minimum required AC distribution equipment available. The inspectors have observed the implementation of the licensee's committed policy of maintaining containment integrity with equipment from more than one electrical train out of service while in modes five and six.

(Closed) Violation (311/83-30-02) This violation involved a failure to maintain and implement the emergency instruction for high reactor coolant pump (RCP) shaft vibration. The inspectors verified that the initial change to the instruction deleting the action requirements for shaft vibration were completed. In addition, the inspector noted that a modification was made to correct the deficiency in the shaft vibration monitor and that action limits were restored to the emergency instruction.

(Closed) Inspector Followup Item (311/83-19-05) The inspector observed that the licensee has completed the installation of the hot leg and cold leg temperature recorders in the control room and the high range area radiation monitor (ARM) in the electrical penetration area to meet the requirements of Regulatory Guide 1.97 and Unit 2 license condition 2.C.7. The installation of the ARM was delayed from December 1983 until April 1984 due to procurement problems. The licensee requested extensions of the completion date in letters dated December 19, 1983 and April 5, 1984.

(Closed) Inspector Follow Item (272/82-36-01) The licensee submitted a supplemental report for Unit 1 LER 82-90/01T on July 13, 1983. The licensee's investigation of the fuel clad failure did not indicate any failure trend due to manufacture or mode of operations. The failure was determined to be apparent secondary hydriding and assumed to be isolated. The inspector had no further questions at this time.

(Closed) Violation (272/82-27-02; 311/82-26-02) This violation included three examples of missed surveillance tests required by the Technical Specifications. The first two examples were for missed Reactor Coolant System (RCS) Water Inventory Balances. Both occassions were due to oversight, but were aggravated by plant conditions, since the licensee can't perform an inventory balance during non-steady state conditions. The licensee changed the shift routine logs so that the RCS Water Inventory Balance would be conducted daily to prevent future occurrence. The third example, failure to perform a Shutdown Margin calculation within 24 hours while in Mode 5 was also due to personnel oversight, however, no administrative or procedural problems were identified by the licensee during their review. Therefore the only corrective action was to counsel the personnel involved. The inspector had no further questions at this time.

(Closed) Violation (272/82-33-01) This violation involved inoperable containment radiation monitors during containment purge and pressure relief operation due to inadequate post modification testing which failed to identify a capped sensing line. The licensee's Operational Test Group (OTG) became fully operational on July 1, 1983. The OTG is responsible for determining the testing requirements for each Design Change Package (DCP) whether fully or partially completed. In addition, in accordance with Administrative Procedure 8, Design Change, Test and Experiment Program, the OTG will review for acceptance the Construction Verification Testing that is performed to verify proper installation of components and also will notify the Operating Engineer if any Operational Tests must be deferred until operating conditions permit the testing. Proper review and evaluation of DCPs by the OTG should prevent future similar violations. The inspector had no further questions at this time.

(Open) Inspector Followup Item (272/84-13-06) This item involved a problem the licensee was experiencing in measuring the force required to trip the Reactor Trip Breakers (RTB) during semi-annual testing required by maintenance procedure M3Q2. It appeared that the test on the A RTB was unsatisfactory because the licensee used a more sensitive instrument to record the trip force than had been used during previous tests. By connecting the visicorder to the RTB trip contacts, the licensee determined that what had appeared to be excessive force required to lift the trip bar was actually the "bounce" of the trip bar after the breakers had opened. Based on this analysis which is documented in the engineering response to DR 84-3159 and an Engineering Department Letter to General Manager - Salem Operations dated April 13, 1984 (DN7 1/01), the licensee changed the method of force measurement in M3Q2 from lifting the trip bar by hand to the use of a weight and pulley arrangement to obtain more precise data. Using the average force required in three tests, the licensee then adds this weight to the trip bar and attempts to trip the RTB with the UV coil. When the licensee attempted this new procedure on 1A , 1A bypass and 1B RTBs, only the 1A bypass RTB successfully passed the test. This procedure differs from the Westinghouse generic procedure for the DB 50 breakers which requires only a force measurement using a fish scale of less than 31 oz. and an addition weight to be added to the trip bar of 20+0-4 oz. for the UV coil trip test. The difference is based on a licensee commitment to trend the force measurement which is not applicable to other licensee's. The licensee was reevaluating the M3Q2 procedure with assistance from Westinghouse at the conclusion of the inspection. The inspector will review the results of the evaluation during a subsequent inspection.

3. Review of Periodic and Special Reports

Upon receipt, the inspector(s) reviewed periodic and special reports. The review included the following: inclusion of information required by the NRC, test results and/or supporting information consistent with design predictions and performance specifications, planned corrective action for resolution of problems, and reportability and validity of report information. The following periodic reports were reviewed:

-- Unit 1 Monthly Operating Report for March 1984

-- Unit 2 Monthly Operating Report for March 1984

-- Radiological Effluent Release Report 15 for July to December 1983

4. Licensee Event Report (LER) Review

The inspectors reviewed LER's to verify that the details of the events were clearly reported. The inspectors determined that reporting requirements had been met, the report was adequate to assess the event, the cause appeared accurate and was supported by details, corrective actions appeared appropriate to correct the cause, the form was complete and generic applicability to other plants was not in question.

Unit 1

* 84-010 Reactor Coolant System - RTD Bypass Line Valve Failures

Unit 2

* 84-006 Electrical Power Systems - Loss of 2B 4KV Vital Bus

84-007 Rod Control Assemblies - Missed Surveillance

* 84-008 Reactor Trip From 99% - False Low Condenser Vacuum Signal

* Denotes onsite followup

Unit 1

84-010 This report documents additional failures of RTD Bypass Line valves as previously reported in Unit 2 LER 84-001. Radiography results showed that 11 valves on Unit 1 have experienced the previously identified stem-to-disk separation failure. The licensee has replaced all of the valves on Unit 1 and plans to replace the Unit 2 valves during the next refueling outage. Additional details of this problem are documented in NRC Inspection Reports 50-272/84-04; 50-311/84-04 paragraph 9a and 50-272/84-08; 50-311/84-08 paragraph 4.

Unit 2

84-006 This report documented a valid test failure of 2B diesel generator when 2B vital bus was de-energized due to bus differential protection relay actuation while paralleling the diesel generator to the bus. During this event, the 2B vital bus was dead for about nine hours to investigate the problem while the unit operated at 100 percent power. Numerous Technical Specification action statements were involved. When the event occurred, all rod position indicators (IRPIs) and rod bottom lights indicated that the rods had been fully inserted due to a loss of the B 230 volt vital bus, however, there were no reactor trip signals and reactor power remained stable at 100 percent. Loss of all IRPI indication placed the licensee in action statement 3.0.3 which requires immediate action to place the plant in a mode in which the action statement does not apply and to complete this action within six hours. The licensee felt it was unsafe to impose a transient on the plant under these conditions and chose to pursue correction of the problem in the existing stable condition rather than a mode change. After one hour and fifty eight minutes, the licensee identified the appropriate transfer switch and restored power to the IRPIs. Because of this problem and the investigation of the problem with the bus, the licensee did not complete testing of the 2A and 2C diesel generators within one hour of the loss of 2B diesel generator as required by Technical Specification 3.8.1.1.a. NRC IE Bulletin 79-27, Loss of Non-Class 1-E Instrumentation and Control Power Systems Bus During Operation requested that licensees prepare emergency procedures to be used by control room operators, including procedures to achieve cold shutdown upon loss of power to each class 1-E and non-class 1-E bus supplying power to safety related and non-safety related instrument and control systems. While the licensee performed a detailed study of the effects of a loss of various 125V instrument and control power buses and made several modifications to minimize the impacts of these type of transients, no detailed procedural guidance was provided to the operators to cope with such problems beyond individual alarm response procedures which are inadequate to address the priorities for the numerous problems encountered in a situation like this. In addition, even after this actual event, the licensee took no corrective action to provide adequate procedural guidance. This is a violation of 10 CFR 50 Appendix B Criterion XVI and section 12.2.16 of the SGS-UFSAR, the licensee's Quality Assurance Program, which requires that conditions adverse to quality be promptly identified and corrected (311/84-15-01).

84-008 This report detailed a reactor trip from 99 percent power due to a turbine trip on low condenser vacuum while licensee personnel were troubleshooting a false low condenser vacuum first out alarm. The licensee has disabled the low condenser vacuum first out alarm while conducting an engineering investigation of the problem under DCRs 1SC-1411 and 2SC-1412. Another overhead annunciator for low condenser vacuum remains operable and the low condenser vacuum turbine trip is unaffected by this action. The inspector will review the engineering investigation results during a subsequent inspection (311/84-15-02).

5. Operational Safety Verification

a. Control Room Observations

Daily, the inspector(s) verified selected plant parameters and equipment availability to ensure compliance with limiting conditions for operation of the plant Technical Specifications and safe plant operation. Selected lit annunciators were discussed with control room operators to verify that the reasons for them were understood and corrective action, if required, was being taken. The inspector(s) observed shift turnovers biweekly to ensure proper control room and shift manning. The inspector(s) directly observed operations to ensure adherence to approved procedures.

b. Shift Logs and Operating Records

Selected shift logs and operating records were reviewed to obtain information on plant problems and operations, detect changes and trends in performance, detect possible conflicts with Technical Specifications or regulatory requirements, determine that records are being maintained and reviewed as required, and assess the effectiveness of the communications provided by the logs.

While reviewing licensee incident report 84-061, Isolation of the Boron Injection Tank (BIT) Recirculation Flow, the inspector noted that Technical Specification action statement 3.5.4.1, which requires that the BIT be restored to operable status within one hour or the unit be in hot standby within the next six hours after the BIT is declared inoperable, was not entered. The limiting condition for operation (LCO) requires that the BIT be operable with a minimum contained volume of 900 gallons, which is verified every seven days by a recirculation flow surveillance test. The SGS-UFSAR states that whenever the plant is at power, a recirculation path is set up to recirculate the BIT contents to and from the boric acid tank (BAT) to ensure the BIT remains full. In this case, the BIT recirculation path was isolated from 10:30 a.m. to 5:00 p.m. on April 27, 1984 with the plant at about 2 percent power. The BIT inlet valve ,2SJ108, was failed closed by tagging closed the air supply to the operator in order to permit repairs to a leaking diaphragm on one of the BAT return valves ,22CV161. Since this condition existed for only five and one half hours the licensee did not violate the Technical Specification LCO, however failure to enter the action statement represents an inadequate understanding of the LCO. This item is unresolved pending review of licensee corrective action (311/84-15-03).

c. Plant Tours

During the inspection period, the inspector(s) made observations and conducted tours of the plant. During the plant tours, the inspector(s) conducted a visual inspection of selected piping between containment and the isolation valves for leakage or leakage paths. This included verification that manual valves were shut, capped and locked when required and that motor operated valves were not mechanically blocked. The inspector(s) also checked fire protection, housekeeping/cleanliness, radiation protection, and physical security conditions to ensure compliance with plant procedures and regulatory requirements.

d. Tagout Verification

The inspector(s) verified that selected safety-related tagging requests were proper by observing the positions of breakers, switches and/or valves.

6. Surveillance Observations

The inspector(s) observed portions of the surveillance procedures listed below to verify that the test instrumentation was properly calibrated, approved procedures were used, the work was performed by qualified personnel, limiting conditions for operation were met, and the system was correctly restored following the testing:

-- Channel Functional Test, 2FT-513, No. 21 Steam Generator Steam Flow Protection Channel II per procedure 2PD2.6.029

-- Channel Functional Test, N31, Source Ranger Nuclear Instrumentation Channel per procedure 2PD16.2.011

-- Channel Functional Test, N32, Source Range Nuclear Instrumentation Channel per procedure 2PD16.2.012

-- Inservice Testing of 23 Auxiliary Feedwater Pump per SP(O)4.0.5.P AF(23)

-- Inservice Testing of Valves - Mode Dependent Valves, of valve 23MS46 per SP(O)4.0.5MD

No violations were observed.

7. Maintenance Observations

a. The inspector(s) observed portions of various safety-related maintenance activities to determine that redundant components were operable, these activites did not violate the limiting conditions for operation, required administrative approvals and tagouts were obtained prior to initiating the work, approved procedures were used or the activity was within the "skills of the trade," appropriate radiological controls were properly implemented, ignition/fire prevention controls were properly implemented, and equipment was properly tested prior to returning it to service.

b. During this inspection period, the following activities were observed:

-- Troubleshooting No. 23 Containment Fan Coil Unit (CFCU) motor and power supply per Work Order No. 948215

-- Recalibration of No. 2SA2 Individual Rod Position Indicator (IRPI) per Work Order No. 941606

-- Replacement of the No. 23 Feedwater Flow Nozzle per Work Order No. 946229

-- Torque measurement testing of 1B Reactor Trip Breaker per M3Q2 and Work Order No. MD947245

c. <u>Findings</u>

-- On April 17, 1984 the No. 23 CFCU motor failed to start during testing. The licensee pursued two troubleshooting paths. The motor was pulled for inspection, and testing of the power supply including the cables, breakers, and vital bus was performed to determine the cause. The motor had two broken stator strap welds. Power supply testing was inconclusive. Based on a previous failure of the stator straps on the No. 15 CFCU motor, the licensee decided to inspect the Nos. 24 and 25 CFCUs motors in addition. This visual inspection was conducted with the assistance of Westinghouse and no further indications of cracked stator welds were found. The licensee Engineering Department will provide a Safety Evaluation based on the inspection program conducted after the failure of the No. 23 CFCU. The inspector will review the evaluation during a future inspection (50-272/84-15-01; 50-311/84-15-04).

-- On April 23, 1984 and May 5, 1984 during startup operations on Unit 2, several rod position indicators (IRPIs) were found reading more than 12 steps below the Rod Group Demand indicator. At both times, the reactor was subcritical and the reactor trip breakers were opened to immediately insert all shutdown bank control rods in accordance with Technical Specification 3.1.3.2.2. Subsequent testing of the IRPIs demonstrated that the Bailey indicators were out of calibration and that the rods had, in fact, been in proper alignment.

-- While observing the repairs to the No. 23 Feedwater Flow Nozzle F-659-2 which was damaged as a result of a water hammer on April 6, 1984, the inspector found that the work was being conducted as non-safety related with no QA provisions required, as documented in Work Order MD 946229. Inspector review of the Unit 2 Master Equipment List (MEL) indicated that the feedwater flow nozzle, which was being replaced with one from Unit 1, was listed as a safety related, QA required component. Further review of current work orders, also indicated that Work Order MD 946237, written to disassemble and inspect the No. 23 Main Feedwater Regulating Bypass valve (23BF40), was also classified as non-safety related, no QA required. However, the MEL listed this component as a functionally safety related, QA required component.

The May 6, 1983 Order Modifying the License required that the licensee implement actions addressed in the licensee's April 28, 1983 letter which included issuance of a verified complete and accurate MEL by May 1983. The two examples of misclassified work orders were caused by failures of the MEL to identify safety related components that are in non-safety related systems, such as Feedwater in this case, as also being components of the safety related reactor protection or engineered safety features actuation systems. This is a violation of the May 6, 1983 Order Modifying the License (50-272/84-15-02; 50-311/84-15-05).

On May 1, 1984, a meeting was held with representatives of the Engineering Department, Salem Station Management and Salem Station QA to discuss the misclassifications. At this time, a 1976 Engineering Department Memorandum was produced that addressed the functional safety related status of a number of components that are present in non-seismically qualified parts of the plant. The memo clearly stated the need for treating these components as safety related with the necessary QA oversight. However, this had not been fully implemented or understood by persons responsible for classifying work on the components, including Engineering Department Sponsor Engineers, and QA personnel responsible for reviewing work order classifications to determine if they were correct.

8. Operating Events

a. On April 6, 1984, at 9:17 a.m., the reactor tripped from full power due to a turbine trip as a result of a technician error during troubleshooting of a spurious Turbine Trip First Out alarm for condenser low vacuum. All systems responded normally during the transient. Inspector review of this event is discussed further in paragraph 4.

b. At 4:33 p.m. on April 6, 1984, with the reactor in hot standby, while stroke testing feedwater regulating valve, 23BF19, per surveillance procedure SP(0)4.0.5V, Inservice Testing, Mode Dependent Valves, the main feedwater line check isolation valve, 23BF22, apparently failed to close. This caused a water hammer in the feedwater and condensate system which resulted in damage to pipe hangers, instrumentation and insulation. The licensee initiated a detailed evaluation of the event which included steam generator inspection, valve disassembly and inspection, stress analysis of the piping, NDE of piping and hangers, etc. In reviewing this event, the inspector found that Integrated Operating Procedure (IOP) 8, Maintaining Hot Standby (HSB) requires that the provisions of Operating Instruction (OI) III.9.3.4, Placing the Condensate System in Service for Cleanup, be followed if the unit will remain in HSB for more than three hours. The unit had been in HSB since the trip discussed above at 9:17 a.m.; about seven hours. The first step of OI III.9.3.4 requires completion of a valve lineup which requires that 23BF13, the isolation valve upstream of the 23BF19, be closed. Although the condensate cleanup strainer was in service at the time of the water hammer, the 23BF13 valve was not closed. The inspector informed the licensee that this was a violation of Technical Specification 6.8.1 which requires that written procedures recommended by Regulatory Guide 1.33, Revision 2, February 1978 be implemented (311/84-15-06). Had this procedure been followed and the 23BF13 valve been closed while stroke testing 23BF19, it is likely that the water hammer would not have occurred or would have at least been reduced in severity since there would have been little or no volume to receive the reverse flow from the steam generator when the immediately downstream 23BF19 was stroke tested with the 23BF22 not fully closed. It was also noted that the licensee added a motor operator to the Unit 2 BF22 valves during the last refueling outage to permit rapid isolation in the event of a feedwater line break. However, no routine use of these valves was incorporated into the licensee procedures. Following this event, the licensee revised IOP 2, 3, and 5 and SP(o)4.0.5.V MD to require that both the BF13 and BF22 valves be closed to prevent recurrence. Further technical review of the water hammer event is discussed in paragraph 11.

c. Following a 17 day outage to investigate and make repairs to No. 23 feedwater line, which was damaged by the water hammer event on April 6, 1984, the reactor was made critical at 11:03 a.m. and the generator was synchronized to the grid at 3:54 p.m. on April 23, 1984. At 4:00 p.m. the turbine tripped due to high high level in No. 23 steam generator and tripped the reactor from 22 percent power, which is above the 10 percent permissive. After licensee investigation identified some binding in the feedwater regulating bypass valve, 23BF40, the valve was disassembled, repacked and reassembled. Though the valve had been damaged during the water hammer event, and subsequently repaired and retested, no further damage was identified at this time. While investigation of the 23BF40 problem was in progress, the acting

Operations Manager authorized restart of the unit on the condition that any problems identified with 23BF40 be corrected. Administrative Directive (AD) 16, Post Reactor Trip/Safety Injection Review, requires that, if the cause of the event is not clearly determined, then the results of the investigation shall be presented to SORC for thorough review. Upon completion of the SORC evaluation, the committee shall make recommendations to the General Manager - Salem Operations on reactor startup. The inspector informed the licensee that this was also a violation of Technical Special 6.8.1.a which requires that written procedures recommended by Regulatory Guide 1.33, Revision 2, February 1978 be implemented (311/84-15-07). When the inspector questioned licensee personnel about the lack of feedwater flow indication recorded for No. 23 feedwater line during this event, they responded that this wasn't unusual at low power and that the pen was probably stuck, even though there was feedwater flow indication for the other three feedwater lines. This problem was not discussed in the post trip review report, although the recorder traces were included.

d. At 9:25 a.m. on April 24, 1984, the reactor tripped from about 4 percent power due to steam flow/feedwater flow mismatch and low level in No. 21 steam generator. Licensee investigation indicated the flow mismatch was caused by improper operation of a turbine stop valve while latching the turbine due to a sticking pilot valve. The licensee repaired the pilot valve and implemented a precaution to prohibit turbine latching with any low steam generator level alarms.

e. At 7:23 p.m. on April 27, 1984, the unit tripped from 30 percent power due to high high level in No. 23 steam generator which caused a turbine trip which in turn caused a reactor trip since power was greater than 10 percent. At the time of the trip, the main feedwater regulating valve, 23BF19, had just been placed in automatic. Prior to that, operators had attempted to place 23BF19 in automatic but had returned it to manual because of unstable feedwater flow indication. The licensee felt this was caused by rust buildup in the sensing lines as a result of the water hammer in No. 23 feedwater line on April 6, 1984. The licensee blew down the sensing lines, recalibrated the level control instruments, and fully instrumented No. 23 level control loop to clearly identify further problems during the next startup. The SORC drew this conclusion based on the fact that the channel II sensing line on No. 23 feedwater nozzle was plugged, even though it appeared that channel I was controlling at the time of the trip. All other sensing lines were clear also when blown down by the I&C department personnel.

The reactor was critical at 1:56 p.m. on April 28, 1984 and entered Mode 1 at 6:40 p.m. At 11:30 p.m., the licensee shutdown the reactor after determining that the 23 feedwater flow channels were inoperable. Subsequent licensee investigation found that the flow venturi in No. 23 feedwater line had broken free from the pipe and moved over two feet up the line during the April 6, 1984 water hammer event. This problem appears to have caused the reactor trips on April 23, 1984 and April 27, 1984. The licensee removed the section of piping containing the flow venturi in No. 13 feedwater line from Unit 1, which is currently in a refueling outage, and installed it in place of the damaged flow venturi. Further investigation of the feedwater regulating valve bypass 23BF40 also indicated that the halves of the block connecting the actuator to the valve stem were not a matched set. The licensee concluded that this was probably causing the irregular stroke observed after the trip on April 27, 1984. The licensee restarted the unit on May 5, 1984 without further problems.

9. Strike Plan Review

The old contract between PSE&G and the International Brotherhood of Electrical Workers (IBEW) Local 1576 expired on May 1, 1984. Negotiations briefly ceased on April 17, 1984, but both parties resumed negotiating again on April 19, 1984. The IBEW represents all personnel on site with the exception of security and office workers and includes licensed reactor operators. On April 24, 1984, a tentative agreement was reached on a new three-year contract. Union negotiators recommended that the membership accept the new terms in a ratification vote scheduled for Monday, April 30, 1984. The licensee was optimistic that the terms would be accepted, however, rejection could have meant a strike. Since results of the vote would not be known until hours before expiration of the old contract, the licensee made contingency plans which were reviewed by the inspectors. In the event of a strike, all licensed positions would have been filled by currently assigned shift SRO's. Sufficient personnel would have been available since Unit 1 is in a refueling outage. A resident inspector was on site during the vote tally and expiration of the old contract. On April 30, 1984, the IBEW ratified the new contract with PSE&G. Results of the contract vote were 2665 for acceptance and 1045 against. There were no pickets or disturbances before or after the ratification vote.

10. Allegation Followup

An alleger called at 2:30 p.m. on April 17, 1984 and indicated that about seven Public Service employees failed to frisk when they exited the Unit 2 containment despite instructions to do so by the health physics technician at the scene. During a subsequent discussion, the alleger expressed concern about a general lack of reverence for safety measures and suggested something should be done. He was willing to identify the individuals involved from their picture badges and stated that one was a female operator. The inspector obtained a list of badge numbers of individuals entering the

Unit 2 containment from the security guard. The inspector also discussed the matter with the health physics technician who said he had only seen one individual exit the area without frisking. He said this individual, a maintenance supervisor, returned and frisked when the health physics technician directed him to do so. The health physics technician was involved in surveying scaffolding being removed from the containment and did not see the others whom the alleger claimed exited without frisking. When the inspector informed the licensee of this allegation, the licensee identified the maintenance supervisor involved and issued a Loss of Radiological Controls report (LCR 051) which resulted in followup counselling of this individual. The licensee also issued a memo to all station personnel reminding them of their responsibility to frisk and to remind other fellow workers of their responsibility if they should forget. In addition, the licensee has implemented periodic Quality Assurance checks of frisking activities and is reviewing the adequacy of the frisking training. The licensee corrective action to resolve this problem was adequate.

11. Feedwater Hammer Event of April 6, 1984

a. Introduction

Fluid transients resulting from disturbances such as fast valve closure can create pressure waves. These pressure waves then travel through a piping system. Depending on the type and magnitude of the pressure wave, localized stressing of the system may occur and, in severe cases, may result in failure of the system boundary and/or damage to adjacent supports resulting from system movement.

b. Event Description

Between each Feedwater Regulating Valve and steam generator (S/G), there are two valves in the main feedwater line, an isolation valve (BF21) and stop check valve (BF22). Valve BF21 is normally open. During normal conditions, the function of the stop check valve is to prevent reverse flow from the S/G whenever the main feedwater pumps are tripped or the main feedwater system is not in operation.

On April 6, 1984, while in hot standby (Mode 3), mode dependent valve in-service testing was is progress. Test procedure SP(0)4.0.5-V-MD requires each Feedwater Reg. Valve (21-24 BF19's) and Bypass Valve (21-24BF40's) to be tested for stroke time determination. Testing had been satisfactorily completed on 21BF19, 21BF40, 22BF19 and 22BF40. Apparently the stop check valve in loop 3 (23BF 22 failed to "check" closed against S/G pressure (1000 psig). When Feedwater Regulating Valve 23BF19 was opened for its stroke time test, a fast reverse flow was developed due to high differential pressure across the Regulating Valve (1000 psig on one side and 500 psig on the other). The reverse flow appears to have subsequently slammed shut the check valve which generated pressure waves resulting in water hammer. These pressure waves propagated through the piping system and caused damage to pipe supports in some locations. The root cause of this event was attributed to a stuck check valve along with an inadequate surveillance procedure. The check valve failure may have been caused by crud buildup since magnetite product was found during post-event valve inspection.

c. Licensee Actions

The licensee took aggressive corrective actions after the event. A task team consisting of personnel from station and engineering groups was formed. The entire feedwater line and S/G were visually inspected. NDE testing was performed on selected locations. In parallel with the inspections, the analytical group, helped by an outside consultant, simulated the water hammer event by using computer code LIQT. The inspector discussed the assumptions used in the analysis with the licensee's cognizant engineer. Preliminary results indicate that both initial peak compression waves (downstream side of 23BF22) and rarefaction waves (upstream side of 23BF22) were about 500-700 psi. The assessment and modeling generally agreed with the observation of piping damage which was located mainly between 23 S/G and Regulating Valve 23BF19. Since the S/G has a very large water volume compared with the feedwater piping system, the effect of pressure waves on S/G internal structure was not expected to have a significant impact. The visual inspection on the S/G internals performed by Westinghouse personnel did not find any damage.

The NRC inspector walked down the feedwater lines for all four steam generators and concurred with the licensee's findings, as follows:

1. The major damage on the piping support system, consisting of rigid struts, spring hangers and snubbers, occurred between the 23 S/G and the air operated feedwater Regulating Valve (23BF19).

2. The support system damage was as follows:

   a) 2FWH-23-11 rigid strut top base plate ripped away from the I-beam support.

   b) 2FWH-23-12 rigid strut broke at the threads.

   c) 2FWH-23-13 rigid strut buckled.

   d) S23FWSN-15A snubber internals inoperable.

   e) S23FWSN-15B snubber internals seized (2 units).

   f) S23FWN-17B snubber internals seized.

3. All four (4) feedwater lines were visually inspected and intact. The licensee described the damage to the involved valves and subsequent implementation of their corrective actions as follows:

   a) The magnetite build-up at the bowl section of motor operated feedwater stop check valve, 23BF22, was cleared and the surface was polished. The valve internals were visually checked and found undamaged.

   b) The inline air operated control valve 23BF19 cam positioner was damaged and replaced with a new positioner. The valve was stroke tested to open at 5.4 psig and fully opened at 15 psig.

   c) The bypass air-operated valve 23BF40 yoke was cracked and its actuator position transmitter was damaged. The actuator was replaced with one from Unit 1.

   The licensee has indicated that there were damaged trunions inside the containment on the feedwater piping; this damage, which was repaired, is being investigated and analyzed. The licensee performed UT, MT, and RT on involved 23 S/G feedwater piping. The results of these examinations will be furnished to NRC for analysis and review.

   In summary, the licensee was engaged in various activities summarized from their preliminary report as follows:

   a) Detailed inspections of:

      1. Feedwater and auxiliary feedwater lines

      2. Support system on the feedwater lines

      3. Steam generator No. 23

      4. Condenser internals

   b) Stess analysis of the feedwater piping

   c) Testing of feedwater heaters and valves

   d) Investigation of potential problems with the involved instrumentation

   e) Removal and replacement of damaged supports, snubbers, etc.

f) The licensee revised the surveillance procedure No. SP(0)4.0.5-V-MD to insure verification of the feedwater stop check valve motor operator in a complete closed position prior to the stroke testing.

The inspector had no further questions.

12. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. The unresolved item identified during this inspection is discussed in paragraph 5.

13. Exit Interview

At periodic intervals during the course of this inspection, meetings were held with senior facility management to discuss inspection scope and findings. On May 8, 1984, the inspector met with licensee representatives and summarized the scope and findings of the inspection as they are described in this report.