

U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-272/87-07 05000272-870312
50-311/87-08 05000311-870312

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: February 24, 1987 - March 23, 1987

Inspectors: T. J. Kenny, Senior Resident Inspector
K. H. Gibson, Resident Inspector

Reviewed by: R. J. Summers
R. J. Summers, Project Engineer
Reactor Projects Section No. 2B, DRP

4/1/87
date

Approved by: L. J. Norrholm
L. J. Norrholm, Chief, Reactor Projects
Section No. 2B, Projects Branch No. 2, DRP

4/2/87
date

Inspection Summary:

Inspections on February 24, 1987 - March 23, 1987 (Combined Report Numbers 50-272/87-07 and 50-311/87-08)

Areas Inspected: Routine inspections of plant operations including: operational safety verification, maintenance, surveillance, review of special reports, regional and 2515 program temporary instructions, allegation followup, site meetings, and a management change. The inspection involved 140 inspector hours by the resident NRC inspectors.

Results: Unit 2 experienced a reactor trip and one violation was identified by the licensee during this report period. These events are described in Section 2 of this report. There were two meetings with regard to the 500KV electrical system at Artificial Island as discussed in Section 7 of this report.

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. Operational Safety Verification

2.1 The following documents were reviewed:

- Selected Operators' Logs;
- Senior Shift Supervisor's (SSS) Log;
- Jumper Log;
- Radioactive Waste Release Permits (liquid & gaseous);
- Selected Radiation Work Permits (RWP);
- Selected Chemistry Logs;
- Selected Tagouts; and,
- Health Physics Watch Log.

2.2 The inspector conducted routine entries into the protected areas of the plants, including the control rooms, Auxiliary Building, fuel buildings, and containments (when access is possible). During the inspection activities, discussions were held with operators, technicians (HP & I&C), mechanics, supervisors, and plant management. The purpose of the inspection was to affirm the licensee's commitments and compliance with 10 CFR, Technical Specifications, and Administrative Procedures.

2.2.1 On a daily basis, particular attention was directed to the following areas:

- Instrumentation and recorder traces for abnormalities;
- Adherence to LCO's directly observable from the control room;
- Proper control room shift manning and access control;
- Verification of the status of control room annunciators that are in alarm;
- Proper use of procedures;
- Review of logs to obtain plant conditions; and,

- Verification of surveillance testing for timely completion.

2.2.2 On a weekly basis, the inspector confirmed the operability of selected ESF trains by:

- Verifying that accessible valves in the flow path were in the correct positions;
- Verifying that power supplies and breakers were in the correct positions;
- Verifying that de-energized portions of these systems were de-energized as identified by Technical Specifications;
- Visually inspecting major components for leakage, lubrication, vibration, cooling water supply, and general operating conditions; and,
- Visually inspecting instrumentation, where possible, for proper operability.

2.2.3 On a biweekly basis, the inspector:

- Verified the correct application of a tagout to a safety-related system;
- Observed a shift turnover;
- Reviewed the sampling program including the liquid and gaseous effluents;
- Verified that radiation protection and controls were properly established;
- Verified that the physical security plan was being implemented;
- Reviewed licensee-identified problem areas; and,
- Verified selected portions of containment isolation lineup.

2.3 Inspector Comments/Findings:

The inspector selected phases of the units operation to determine compliance with the NRC's regulations. The inspector determined that the areas inspected and the licensee's actions did not

constitute a health and safety hazard to the public or plant personnel. The following are noteworthy areas the inspector researched in depth:

Unit 1

- Unit 1 began this report period at 100% power.
- On March 1, 1987, the island lost the 500 KV Keeney transmission line (5015) which connects Hope Creek Generating Station with the State of Delaware across the Delaware Bay. The loss of the line forced all the generating units of Artificial Island to reduce power to 75% in order to stay within the stability limits of the 500KV electrical grid in the northeast sector. The unit was reduced to 75% power on March 2, 1987.
- On March 8, 1987 at 11:47 p.m., the unit was removed from service to repair rod drive vent fans, re-connect No. 1 auxiliary power transformer and complete other smaller repairs to the unit. The unit was in Mode 3 at 6:00 a.m. on March 9, 1987.
- On March 10, 1987, No. 1F Group Bus was taken out of service in support of work on No. 12 Station Power Transformer. The 115VAC Control Center failed to transfer to its alternate power supply, the 2H Group Bus, resulting in a loss of control power to the auto-start initiation logic for both diesel driven fire pumps.

Both diesel fire pumps started on loss of AC power to the auto start initiation logic, and an alarm was received in the control room. When station personnel investigated the alarm, they found the diesel fire pumps operating and notified the control room of the situation. The fire pumps were stopped, then placed in manual control to prevent unnecessary operation. An operator was stationed in the fire pump house to monitor proper fire suppression header pressure and start the fire pumps if necessary. Site maintenance was notified of the failure of the 115VAC Control Center to swap to its alternate power source. The licensee made the necessary notification in accordance with Technical Specifications. The repairs were made and the system was returned to service.

- On March 12, 1987 at 11:00 a.m., a licensee radiation protection technician identified a normally required locked, High Radiation Area (greater than 1000 mrem/hour) door, for the Unit No. 1 bioshield area, propped open with a yellow anti-C bootie. The door had been previously verified locked closed by radiation protection personnel at approximately 9:00 a.m. that morning.

As a result, the licensee's management took the following corrective actions:

1. Checked all locked High Radiation Area doors in both Units 1 and 2. No other deficiencies were found.
2. Reviewed PREMS (computerized access and exposure monitoring system) and Radiation Work Permit (RWP) data and identified six (6) personnel who had been in the bioshield area between 9:00 a.m. and 11:00 a.m. One of the six was the technician who identified and reported the deficiency. Access to the Auxiliary Building for the six individuals was administratively barred (via PREMS) until the licensee's investigation was complete.
3. The thermoluminescent dosimeters (TLD) worn by the six were processed and no excessive or unusual exposures were identified.
4. Each of the six were interviewed and counseled by radiation protection management as to the requirement and importance of keeping High Radiation Area doors locked. None of those interviewed admitted propping the door open. It was also determined that no one was in clear sight of the door while it was open.
5. Distributed a letter to station managers concerning the issue, which was to be discussed with their personnel at the next safety meeting.

In addition, the Salem General Manager discussed the incident with the six individuals and placed a letter describing the incident into each person's personnel file.

Failure to maintain a High Radiation Area door locked is a violation of Technical Specification 6.12.2. (50-272/87-07-01) However, in accordance with 10 CFR 2, Appendix C, a notice of violation is not being issued since this violation meets all of the following criteria:

1. It was identified by the licensee;
2. It fits in Severity Level IV or V;
3. It was reported to the resident inspectors;
4. It was corrected, including measures to prevent recurrence, within a reasonable time; and

5. It was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation.

The inspector reviewed the licensee's corrective actions and considers this item closed.

- On March 16, 1987 at approximately 1:00 p.m. during plant startup, a leak was identified by the secondary plant operator, on No. 12 steam generator feed pump (SGFP) recirculation line to the condenser. No. 11 SGFP was placed in service and the leak was isolated. The recirculation line is only in service during startup or trip of the unit. The break in the line occurred at a point where erosion had thinned the section of piping. Thinning had been identified in this area by the licensee previously, but the UT method of identification was performed on quadrants other than where the break occurred. The erosion was localized to about a one inch strip near the bottom of a six inch header, downstream of an orifice. Because of the previously identified thinning in the area, the licensee had issued Design Change Requests 2SM00192 for Unit 2 (issued December 19, 1986) and 1SM00201 for Unit 1 (issued February 12, 1987). These requests were to disposition a Deficiency Report which identified the thinning. The design change on Unit 1 was scheduled for the next refueling outage and the piping was to be replaced with chrome-molly steel. (See Section 3 of this report for more details.)
- On March 19, 1987, the licensee was going to perform a hydrostatic test on a section of Auxiliary Feedwater (AFW) piping in accordance with Section XI of the ASME code. After the operations department isolated the section of piping, five hours passed before the test technicians arrived at the No. 11 AFW pump and found that one of the gages on the suction side of the pump was pegged high (600#). The technicians removed the gage and replaced it with a test gage and read a pressure of 900 pounds. (The suction piping is schedule 40 piping rated for 195 psig). The pressure was relieved and an investigation was started. The results of the investigation were:
 1. The overpressure condition happened because check valves in the AFW system leaked by, which caused the main feed system to pressurize the piping back through the No. 11 AFW pump to the suction isolation valve. The licensee has been monitoring this piping for steam binding in the AFW system, but has never seen temperatures greater than 120 degrees F within the piping, which indicated that the leak was small. It was also calculated that, over a five hour period, about one quart of water leaked by the check valves.

2. Magnetic particle testing was performed on all the welds that were subjected to the overpressure. No cracks or weld failure indications were identified.
3. Stress calculations were performed on the piping. The calculations indicate that all components were within their stress limits.
4. The licensee contacted the pump manufacturer who stated that the pump seals were the only vulnerable component of the pump. The seals were designed for a pressure of 1000 psi.
5. The licensee contacted the valve manufacturer who stated that, if the valves could be manipulated and if there was no physical damage, they were all right. The valves were inspected and cycled.
6. The licensee is investigating to identify what procedures and measures will have to be taken to preclude similar incidents.

The resident inspector has examined the documents related to the licensee's investigation and has no further questions at this time.

The pump was tested and returned to service on March 20, 1987 at 3:37 p.m.

- On March 27, 1987, No. 11 SGFP was returned to service and the unit power was increased to 71%, 790 MWe (maximum generation with the Keeney 500KV line out of service).

Unit 2

- The unit began this report at 100% power.
- On March 1, 1987, the unit power was reduced to 75% due to the loss of the 500KV Keeney line.
- On March 12, 1987 at 9:30 a.m., the unit tripped from 100% power on an indicated "Generator Differential or Loss of Field" which tripped the turbine and the reactor. The direct cause of the trip was loss of the generator field when the field breaker opened. All systems functioned as designed.

Curves and recordings showed that the unit was operating within the design range of the voltage regulator. The licensee began an investigation into the trip with the following results:

1. All relays and circuits associated with the voltage regulator, both de-energized and energized, were tested. In addition, related control room annunciators were tested. The testing indicated that the equipment associated with the voltage regulator was not the direct cause of the field breaker opening.
2. After a meeting with the SORC and members of the test group, plant management determined that the probable cause for the trip was the operation of the generator with too much "out" vars (volts-amps-reactive, causing an over excited generator), which had been ordered by the system load dispatcher. The amount of vars was within the operating curves supplied by the generator manufacturer.
3. The generator operating curves were re-issued and a restriction of 400 "out" vars has been established as a maximum continuous limit.

- On March 14, 1987 at 9:47 a.m., the unit was returned to service. No further problems with the field breaker or main generator were encountered. The unit was operating at 72% power with 790 MWe at the close of this report period.

3. Maintenance Observations

The inspector reviewed the following safety related maintenance activity to verify that repairs were made in accordance with approved procedures and in compliance with NRC regulations and recognized codes and standards. The inspector also verified that the replacement parts and Quality Control utilized on the repairs were in compliance with the licensee's QA program.

During Unit 1 startup on March 16, 1987 at approximately 1:00 p.m., the licensee identified a leak on No. 12 steam generator feedpump (SGFP) recirculation line to the condenser. The leak resulted from a 1/2 inch by 1 inch hole in the piping near a carbon to carbon weld located between a stainless steel flow restricting orifice and valve 12BF31 (see Attachment 3 to this report). The piping is 6 inch A106 Grade B carbon steel with 0.432 inch nominal wall thickness. The break in the pipe occurred where erosion had thinned the pipe near the weld backing ring which protruded into the pipe. Although thinning in the recirculation piping had been identified previously by the licensee (discussed in Inspection Report 50-272/86-32; 50-311/86-36), the section between the carbon to carbon weld and carbon to stainless weld had not been inspected.

Upon discovery of the leak, immediate actions by the licensee included shifting to No. 11 SGFP and isolating the leaking recirculation line. Further licensee actions included:

1. Cut out the section of pipe, as shown on attachment 3, for analysis to determine metallurgical root cause of the failure. The metallurgical laboratory's preliminary assessment of the cause was water impingement erosion as evidenced by flow disturbances indicated by swirl patterns observed through an etching technique.
2. Performed ultrasonic (UT) inspection of No. 11 SGFP recirculation piping. The minimum wall thickness was identified as 0.360 inches (localized area). This has been determined acceptable by the licensee in their engineering analysis.
3. Performed UT inspection of Unit 2 SGFP recirculation lines. These lines do not have an orifice, however the BF 32 valves are throttled to effectively act as an orifice. Results indicate a minimum wall thickness of 0.305 inches (localized area at the valve). This also was determined as acceptable by the licensee through their engineering analysis.
4. Qualified a welding procedure for A106 carbon to 410 stainless steel.
5. Welded in new A106 piping as shown on attachment 3. The inspector noted that the backing ring technique was not used because the licensee believed that the backing ring of the previous weld protruding into the piping may have contributed to the thinning.

The following data represents the normal operating conditions of the SGFP recirculation lines which are in operation (BF 31 valve open) only during startup and following a trip;

Chemistry

| | |
|------------------------|------------------|
| pH: | 8.8-8.9 |
| Dissolved Oxygen: | less than 5ppb |
| Hydrazine: | 30ppb |
| Cation Conductivity: | 0.06 micro-mho |
| Specific Conductivity: | 2.5 micro-mho |
| Ammonia: | 0.25 ppm |
| Chloride: | less than 0.1ppb |
| Sulfate: | less than 0.1ppb |
| Sodium: | less than 0.1ppb |
| Potassium: | less than 0.1ppb |
| Calcium: | less than 0.1ppb |
| Magnesium: | less than 0.1ppb |
| Iron: | less than 4ppb |
| Copper: | less than 1.0ppb |

Velocity

0 ft/sec - 28 ft/sec @ shutoff head, with discharge valve closed;
nominally 12 ft/sec.

Temperature Range

Startup: 100 Degrees F - 200 Degrees F
Trip: 400 Degrees F - 100 Degrees F

Operation

Unit 1 for 1 year period - approximately 96 hours/pump on recirculation flow path.

The inspector monitored the licensee's progress during replacement of the piping and testing of the other pump and unit recirculation piping. In addition, the following documents were reviewed:

- Code Job Package No. 2-87-060;
- Deficiency Report No. SSP-87-049;
- Work Order No. 870316027;
- Welding Procedure Specification NDWP-13;
(SA-106 Grade B to SA-106 Grade B)
- Welding Procedure Specification NDWP-11;
(SA-240 Type 410 to SA-106 Grade B)
- Procedure Qualification Record No. PQ 141;
- Weld Map for DR No. SSP-87-049;
- Weld History Records;
 - M-S1-FWR-12-19-A
 - M-S1-FWR-12-20-A
 - M-S1-FWR-TDWJN-171
 - M-S1-FWR-TDWJN-172
 - M-S1-FWR-TDWJN-173
- Code Job Package Approval Cover Sheet;
- Maintenance Instruction A-28 "Department Control of Code Work";
- Inspection Point Checklist; and,
- Hot Work Permit (Hot Work Nos. 587-0317001 and 587-0320004).

No violations were identified. The metallurgical laboratory's report will be reviewed by the inspector upon receipt from the licensee.

4. Surveillance Observations

During this inspection period, the inspector reviewed in-progress surveillance testing as well as completed surveillance test packages. The inspector verified that the surveillance tests were performed in accordance with licensee approved procedures and NRC regulations. The inspector also verified that the instruments used were within calibration tolerances and that qualified technicians performed the surveillance tests.

The following surveillance tests were reviewed:

4.1 Unit 1

| <u>Work Order Number</u> | <u>Procedure</u> | <u>Description</u> |
|--------------------------|------------------|--|
| 80320020 | 1PD-16.3.007 | Nuclear Instrumentation System/Power Range Channel 1N41 Calibration Check |
| 870322034 | 1PD-4.2003 | Radiation Monitoring System - Channel Functional Tests, 1-R5 Refueling Building Area Radiation Monitor (ARM), 1-R9 Fuel Storage Area ARM |
| 870322035 | 1PD-4.2.004 | |

Also, the inspector witnessed portions of a flux map on Unit 1 per Reactor Engineering Manual Part 12 - Flux Mapping Procedures and Reactor Engineering Manual Part 13 - Incore Flux Mapping System Operation. During power up of the incore instrumentation, the licensee discovered that the detectors would not move. Investigation by the licensee revealed that the six drive unit breakers had not been closed following the recent Unit 1 mini-outage in which detector "D" was replaced. A containment entry was made, the breakers returned to the operable condition, and the flux map completed.

Entry into the seal table room is controlled by use of a key which will allow the door to be unlocked only when the six drive unit keys are correctly positioned and the six corresponding breakers are open. Repositioning of the drive unit keys and breakers may have occurred several times during the mini-outage by several station groups including Radiation Protection, Reactor Engineering, ISI and Operations

in order to facilitate seal table entries and flux drive testing. However, it appears that the responsibility for ensuring that the drive unit keys and breakers are returned to operable condition prior to startup is not defined. For ALARA considerations, in that an unplanned at power containment entry was required to close the breakers, the inspector is concerned that this responsibility has not been defined.

The inspector discussed the concern with licensee management. The licensee is developing a checklist system requiring sign-offs for each entry and exit from the seal table room. The licensee is also considering several other options to ensure the flux drives are operable prior to startup. The inspector will review the controls when implemented.

4.2 Unit 2

| <u>Work Order Number</u> | <u>Procedure</u> | <u>Description</u> |
|--------------------------|------------------|---|
| 870201002 | M10-SST-028-2 | Fire Damper Functional Test (18 Mo.) - The inspector witnessed testing both from the control room and in the field. |

4.3 Unit 1 and 2

TI 2515/64, Rev. 1, Near Term Inspection Followup to Generic Letter 83-28 "Required Actions Based on Generic Implementation of Salem ATWS Events"

Item 04.05b of the TI requires verification of the licensee's performance of surveillance testing of the shunt trip attachment and manual trip capability for the RTS breakers. The inspector reviewed the following licensee procedures and has previously witnessed portions of these tests.

- 1IC-18.1.006 Solid State Protection System Reactor Trip -
2IC-18.1.006 Breaker and Permissive P-4 Test Prior to S/U
 - Train A
- 1IC-18.1.007 Solid State Protection System Reactor Trip -
2IC-18.1.007 Breaker and Permissive P-4 Test Prior to S/U
 - Train B

- 1IC-18.1.010 Functional Test, SSPS - Train A Reactor Trip
2IC-18.1.010 Breaker UV Coil and Auto Shunt Trip
- 1IC-18.1.011 Functional Test, SSPS - Train B Reactor Trip
2IC-18.1.011 Breaker UV Coil and Auto Shunt Trip

The inspector concluded that the necessary surveillance tests are in place to satisfy the concerns of Item 04.05b of the TI.

- 4.4 During the review of Pressurizer Overpressure Protection System, surveillance tests performed on the system for both units were reviewed. (See section 6 for details) The inspector concluded that the systems on both units function as designed.

No violations were identified.

5. Review of Periodic and Special Reports

Upon receipt, the inspector 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 - February 1987
- Unit 2 Monthly Operating Report - February 1987

No violations were identified.

6. Regional and 2515 Program Temporary Instructions (TI's)

6.1 TI-RI-86-02 - Subject: Inspection of General Electric Type AK-F-2-25 Breakers.

- The resident has determined that this type of breaker is not used at Salem Station.

6.2 TI 2515/64 Subject: Near Term Inspection Followup to Generic Letter 83-28 "Required Actions Based on Generic Implementation of Salem ATWS Events."

- See Section 4.3 for details.

6.3 TI 2515/19 Subject: Reactor Vessel Transient Pressure Protection for PWR's.

6.3.1 Background

The Pressurizer Overpressure Protection System (POPS) was installed to mitigate the severity of low-temperature overpressure transient conditions in a pressurized water reactor. Based on nuclear industry operating experience these transients had usually occurred during startup or shutdown operations when the reactor coolant system (RCS) was in a water-solid condition (with no steam bubble in the pressurizer). During this condition minor changes in RCS temperature and/or related systems pump starts can create major pressure transients.

The operating nuclear power plants were required to install the POPS. Salem Station installed the systems as follows: The Unit 1 system was installed in 1977-78 and the Unit 2 was installed during construction. Unit 1 design (explained later) was installed on the existing power operated relief valves (PORV's). Unit 2's design differed in that parallel valves (Marrotta) were installed for the purpose of the low temperature relief function. Both units' relief systems were installed such that the overpressure relief function was aided by a relief valve in the RHR pump suction piping. The setpoint of this valve was then reduced from the original design of 425 psig to 375 psig. This arrangement has been evaluated in the 50.59 review and safety analysis.

6.3.2 Inspection

The inspector reviewed the documents listed in Attachment 2 of this report and noted that the design of Unit 1 was installed on the existing PORV's and must be armed by the operators utilizing key switches, in the control room, during plant cooldown. Once enabled, the system is fully automatic. Unit 2 was designed utilizing Marrotta valves in parallel with the PORV's, to relieve pressure transients. However, the operator still had to manually enable the system during cooldown. This is contrary to the direction given for plants licensed after April 18, 1980. The inspector determined, after a review of the Safety Evaluation Report (SER) and discussions with NRC-Office of Inspection and Enforcement, that, since the design was initiated prior to April 18, 1980, the manual feature was allowed as was discussed in the SER. The licensee has since determined that the Marrotta valves were very difficult to keep operational and had caused inability to shut down Unit 2 in an orderly manner. They also made restart of the unit difficult. In addition, an incident occurred (a stuck open Marrotta valve, reference LER 84-18, 50-311) which caused a safety injection and a difficult plant shutdown. As a result the Unit 2 system was redesigned in September, 1983 to be like Unit 1 and is currently operating in that configuration.

The inspector has determined the following with regard to the Unit 1 and 2 POPS:

- The design meets or exceeds the requirements of Appendix G of 10 CFR 50 and there are drawings depicting the design. The design also meets the single failure criteria for electrical and mechanical systems.

A backup air supply system, in excess of the recommended 10 minutes, is provided for PORV operation in the event the station air system is lost.

- A 10 CFR 50.59 evaluation was performed and all setpoints and postulated accidents were considered, including calculations for opening times over temperature ranges likely to be seen in a startup or shutdown condition.
- Procedures are in place to minimize both time in water-solid conditions and the temperature differential between steam generators and the reactor vessel while in a water-solid condition; and, to restrict pump starts during water-solid conditions.
- Alarms are in place to alert operators, during plant cooldown, to the need for the POPS and procedures are in place to test the system prior to placing it in service. There are also alarms to alert the operator if a pressure condition is approaching the relief valve setpoints while POPS is in service.
- The operators have received training on the above procedures and design changes.
- The systems were installed in accordance with station approved procedures and construction practices.
- There are surveillance procedures in place to test the system in accordance with Technical Specifications.

6.3.3 Conclusion

The inspector concludes that both units have an operable POPS and has no further questions at this time.

No violations were identified.

7. Allegation Followup

Region I received an allegation from an individual who was briefly employed by a contractor at Salem. He alleged that he was originally hired to do work which involved no radiation exposure. But upon arrival at the site, he was reassigned to work in a radiation area. The inspectors determined that the individual received approximately 20-30 millirem exposure while at Salem, which is within the 10 CFR 20 and licensee's administrative exposure limits. Region I referred the allogger to the U.S. Department of Labor since the concern appears to be a labor issue.

8. Site Meetings

Two meetings on the Salem electrical distribution system were held during this report period. The following are summaries of these meetings. The attendees at both meetings are listed in Attachment 1 of this report.

- 8.1 An NRC/PSE&G meeting was held on February 24, 1987 to discuss the licensee's short and long term corrective actions pertaining to the Salem 4KV electrical distribution system as a result of the August 26, 1986 false loss of offsite power event.

The meeting discussion included: the root cause of the August 26 event, review of the PTI (licensee consultant) model and validation, short term relay scheme modification, and status of the long term electrical study. The licensee has identified the root cause of the August 26 vital bus "flip-flopping" between the station power transformers (SPT) to be the failure of the "A" 91% transfer relay on the No. 22 SPT to reset at the 95% value. The licensee's short term relay scheme modification consists of eliminating the 91% transfer relays on the SPTs, adding three 91% undervoltage (UV) relays on each vital bus and reducing the reset value to 92.25%. The long term study is projected to be complete in July 1987.

The licensee has committed to include, with their February update letter for NRC review, a Justification for Continued Operation for the revised relay scheme and a return to normal auxiliary power transformer configuration.

- 8.2 An NRC/PSE&G meeting was held on March 10, 1987 to discuss the licensee's actions and plans regarding the loss of the 500KV Keeney line which occurred on March 1, 1987 when an oil tanker had a collision with two of the towers which support the line. The line was severed and is inoperable.

During the course of the meeting the licensee discussed the following agenda:

- Problem Description
 - Generalized Stability Analysis
 - Hope Creek/Salem Stability Guidance
- Analytical Techniques
 - Available Models
 - Model Comparison

- Future Operational Options
 - Remain at Reduced Power
 - Restore 500KV Circuit
 - Unit Trip Stability Protection
- Schedules
- Degraded Grid Submittal

The conclusion reached was that, as a result of the loss of the 500KV Keeney line, the next most important line leaving or entering the combined Salem and Hope Creek stations was the 500KV Deans line to Salem. The licensee performed simulated modeling with regard to the additional loss of the Deans line and has determined, in the simplest terms, that only 2000 MWe can be generated with the loss of the Deans line, and still maintain system (electrical) stability on the 500KV system. Therefore, the load generated by Salem and Hope Creek generating stations should be limited to 2000 MWe until one of the Future Operational Options (see above) can be incorporated.

The licensee presented a best estimate time frame for the completion of repairs on the Keeney line. This could take, depending on piling damaged caused by the tanker, anywhere from 8 to 18 months.

The licensee also presented a conceptual design to trip Salem Unit 1 if the Deans line were to be lost. This would enable operation at or near 100% power for all three units at the two stations. In the event the Deans line were lost, Unit 1 would trip leaving the remaining two units generating less than the 2000 MWe necessary for 500KV stability. The NRC will review the design change when available.

The licensee has decided that the unit trip upon the loss of the Deans line concept would be an interim operating scheme until the Keeney line could be restored or another 500KV line could be run from Deans to New Freedom.

The licensee has been operating all three affected units at reduced power and has committed to do so until the 500KV system can be restored or the unit trip concept has been installed.

No violations were identified.

9. Management Change

Public Service Electric and Gas announced, on March 17, 1987, the election of: Corbin A. McNeill, Jr. as Senior Vice President - Nuclear; and, Steven E. Miltenberger as Vice President - Nuclear Operations effective April 6. Mr. McNeill has been Vice President - Nuclear since 1985 and Mr. Miltenberger has been General Manager - Nuclear Operations for Union Electric Company in Fulton, Missouri.

10. Exit Interview

At periodic intervals during the course of the inspection, meetings were held with senior facility management to discuss the inspection scope and findings. An exit interview was held with licensee management at the end of the reporting period. The licensee did not identify 10 CFR 2.790 material.

ATTACHMENT 1

Meeting of February 24, 1987

PSE&G

R. Skwarek
W. Drummond
D. Dodson
P. O'Donnell
L. Griffis
M. Bachman
F. McCann
W. Moo

NRC

L. Bettenhausen
L. Norrholm
O. Chopra
K. Gibson
F. Paulitz

Meeting of March 10, 1987

PSE&G

T. Piascik
J. Hebson, Jr.
R. Wernsing
B. Burricelli
L. Reiter
J. Leech
D. Dodson
B. Preston
U. Polizzi
M. Morroni
R. Skwarek
L. Corletta
R. Schoenberger
L. Hajos
J. Boettger
C. McNeill
L. Miller
R. Salvesen
J. Zupko, Jr.

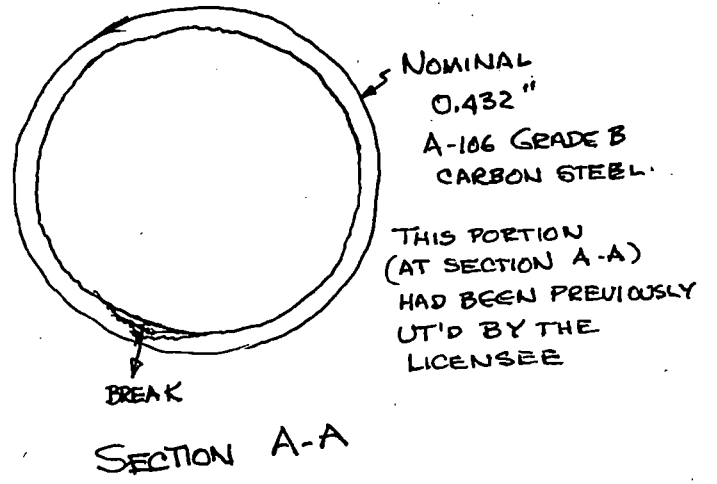
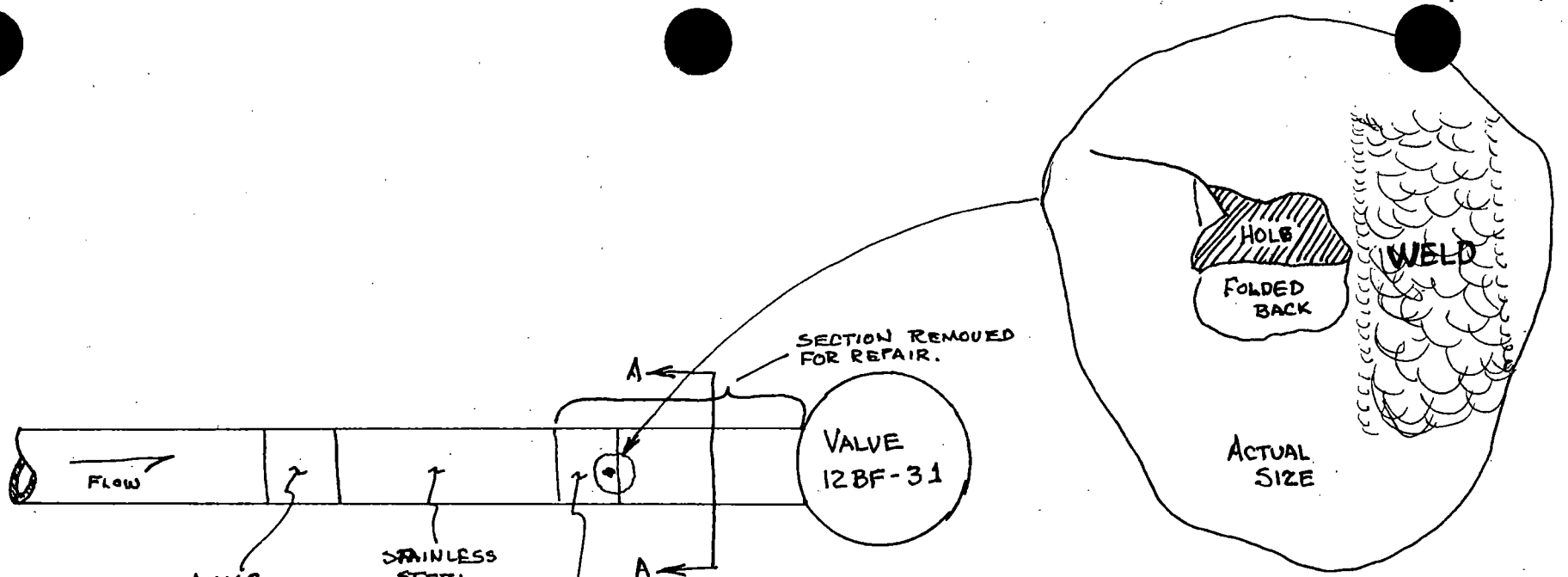
NRC

L. Bettenhausen
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O. Chopra
T. Koshy

ATTACHMENT 2

Documents reviewed for Pressurizer Overpressure Protection System.

- Technical Specifications, Units 1 and 2
- FSAR
- Station Procedures, Units 1 and 2
 - 21C-2.6.071 Channel Functional test for 2PT-405
Reactor Coolant Pressure Indication and 2RH2 Interlock
 - 21C-2.6.070 Channel Functional test for 2PT-403
Reactor Coolant Pressure Indicator and 2RH1 Interlock
 - II.1.3.4 Reactor Coolant System Filling and Venting
 - II.1.3.1 Reactor Coolant Pump Operation
 - II.2.3.4 Pressure Overpressure Protection - Operability Check of
PR1 and PR2
 - Salem Training Manual
- Design Changes
 - Design Change Package for installation of Pressurizer
Overpressure Protection (POP) for Unit 1
 - Design Change Package for modification to POPS on Unit 2
 - SGS/M-DM-042 Design calculations for POPS on Units 1 and 2
- Unit 2 Safety Evaluation Report original - Supplement 6



NOT TO SCALE
VIEWED FROM UNDER THE PIPE