PDR

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

CHAIRMAN

June 3, 1994

The Honorable Joseph R. Biden, Jr.
United States Senate
Washington, D. C. 20510

Dear Senator Biden:

On behalf of the Commission, I am responding to your letter dated May 18, 1994, concerning the operation of Public Service Electric and Gas Company's (PSE&G) Salem Generating Station. Upon receipt of that letter, I asked the staff to prepare a direct response to the points in your May 11 and May 18 letters. I have enclosed (Enclosure 1) the staff's response to the issues expressed in both letters.

I realize that some of the points in your May 11, 1994, letter were not addressed as clearly as they could have been in the NRC staff's reply to you dated May 14, 1994; nevertheless, I want to assure you that the staff had fully considered the information provided in your letter of May 11 prior to granting permission to PSE&G to restart Salem Unit 1 on May 14. In addition, a public briefing was held for the NRC Commissioners by the staff and the licensee on May 9, 1994. The Commission was satisfied with the staff decision to grant PSE&G permission to restart Salem Unit 1 on May 14, 1994. As was noted in the staff's May 14 letter to you, enforcement action related to this event is still under consideration.

The staff made the decision to allow Salem Unit 1 to restart following completion of the Augmented Inspection Team's (AIT) review of the event. The issues that required resolution prior to restart of Salem Unit 1 involved four principal concerns:

- repair and improvement of certain components (i.e., power-operated relief valves, the controllers for the main steam atmospheric relief valves, and the solid state protection system);
- procedural improvements related to operator actions (e.g., guidance addressing conditions that affect the operation of the circulating water system, vessel level monitoring, loss of condenser vacuum, and turbine trip);
- improvements in operator training (including communications, resource management, and revised procedures) relative to the lessons learned from this event; and

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- management effectiveness (i.e., immediate onshift management oversight).

Enclosure 2 summarizes the specific details of actions completed by the licensee related to these areas of concern. The NRC staff evaluated and where applicable, inspected each of the licensee's restart related activities before authorizing restart.

Although all of your points are addressed in Enclosure 1, I would like to speak specifically to two technical points that you raised. First, problems with the power operated relief valves (PORVs) were found as a result of questions raised by the AIT and subsequent review by the licensee following this event. However, the PORVs were cycled over 200 times during the event and remained functional. The PORVs served their function of preventing a challenge to the primary safety valves as the primary safety valves did not open during the event. The components of the PORVs demonstrating wear or damage were replaced with modified internals prior to restart of the unit.

The second point is the licensee's continuing problems with grass clogging the circulating water screens during certain times of the year. This challenge falls within the plant's design basis. The plant design and operator actions should have been able to respond to this challenge without experiencing the difficulties associated with the April 7 event. Therefore, the staff has required and the licensee has taken several actions to prevent this type of event in the future, including procedure changes, design changes, and enhanced operator training.

In both of your letters, you voiced concerns about the effectiveness of the management of Salem and the NRC's role in effecting change. The Commission believes that the level of performance at Salem can and should be improved; nevertheless, the concerns have not reached the level that would require shutdown of the facility or denial of restart. In order to determine whether a licensee requires increased surveillance through the NRC's inspection process, the NRC has established a formal program whereby senior NRC managers review the agency's observations and findings regarding operating nuclear reactors and plan a coordinated course of action for those plants whose performance is of concern. This process is currently being applied to Salem to determine if additional surveillance of the facility is required.

While a review of the Unit 1 issues as they applied to Salem Unit 2 was not a condition for restart of Unit 1, the NRC staff did review the Unit 1 issues as they applied to Salem Unit 2. This matter was identified as item "D" in Enclosure 2. The procedure revisions and operator training enhancements resulting from the event have been implemented at Unit 2. When Unit 2 is shut down for refueling in October 1994, we expect that these hardware modifications will be performed.

I hope you have found this letter responsive to your concerns. I look forward to meeting with you on June 8, 1994 to discuss these and any other issues relative to this matter.

Sincerely,

Ivan Selin

Ivan Selin

Enclosures:
1. Detailed response to questions and concerns
2. May 14, 1994, enclosure to letter addressing restart issues

ENCLOSURE 1*

QUESTION 1. Can the licensee prove that it can and will operate the plant any differently in the future than it has in the past?

ANSWER:

The licensee has implemented programs that can result in performance improvements. The NRC believes that the licensee is operating and managing the plant better since the establishment of the Nuclear Department Tactical Plan developed from the findings of the licensee's Comprehensive Performance Assessment Team (CPAT). The CPAT effort was initiated in July 1993 in response to growing NRC concerns with continuing management and performance deficiencies. Examples of performance issues which raised these concerns included (1) the frequency of NRC Augmented Inspection Team responses (one per year since 1991); (2) the higher than normal plant trip frequency exhibited at Salem; and (3) other recurring deficiencies that caused the NRC to question management's ability to effectively resolve problems.

The Tactical Plan outlines the agenda to achieve meaningful changes in the way PSE&G conducts the management and operation of the Salem facilities. While some aspects are currently in progress (such as restructuring of several departments to dedicate personnel resources to each Salem plant, acquiring additional nuclear department staff, and re-evaluation of currently assigned supervisors and managers for effectiveness and ability), the licensee has

* Many of the points of this enclosure may be visualized more clearly by reference to the diagram included after Enclosure 1.

completed some significant short-term actions. For example, the former General Manager-Salem Operations was replaced by the current Vice President-Nuclear Operations, several supervisory and technical personnel were replaced or reassigned in an effort to affect better quality of operations, supervisors and managers have been directed to spend more time in direct management and oversight of activities, and additional department managers have been assigned to the Maintenance Mechanical and Maintenance Controls organizations. Other changes include the required management review and approval of troubleshooting plans and procedures, and the initiation of the Augmented Independent Oversight function to provide continuous coverage of plant activities.

While none of these changes, taken or planned, provides absolute assurance that the licensee will be able to improve, NRC believes that the licensee has and will continue to operate the Units safely.

QUESTION 2. While the documentation offers some insight into Salem's operations, it does not provide any statement of conclusions or analysis upon which a restart decision should rest.

Notably, the licensees's full submittal was received by your office on May 13, 1994; the NRC's analysis was completed that same day. Given the short time frame for review, I question the degree of confidence that you could have gained in PSE&G's ability or even intention to correct operational problems at the Salem 1 facility.

ANSWER:

The Enclosure to the staff's letter to you dated May 14, 1994, provided the restart issues that were identified by the staff for resolution prior to restart. The Enclosure provided a statement of the agency's conclusion for each item based on an assessment of the licensee's submittals on the matter and concurrent independent inspection or assessment of the specific issue or activity.

The NRC's analyses of the issues and restart decision were not completed in one day. While one of the licensee's submittals (which provided only supplemental information, as requested by the NRC staff) was dated May 13, 1994, the agency's assessment of the licensee's readiness for restart actually began when the NRC's Augmented Inspection Team (AIT) completed its on-site inspection activities on April 21, 1994. Since that time, the NRC staff was continuously involved, monitoring the licensee's corrective actions, conducting an inspection associated with restart issues, and assessing PSE&G's resolution of the technical issues that were contributors to the event. Additionally, the staff reviewed and assessed other licensee submittals that preceded the May 13 submittal (i.e., submittals dated April 25, 29, and May 10, 1994). Further, on April 26 and May 6, 1994, public meetings were held with the licensee; and on May 9, a public briefing was held for the NRC Commissioners by the staff and the licensee. Thus, the staff's efforts in the preceding weeks, during the course of normal business, enabled them to provide a timely response to the licensee's request to commence restart activities in their second letter dated May 13, 1994.

QUESTION 3. A major deficiency of your letter is that it does not assure me that the NRC will take any responsibility in the event that Salem encounters future problems, nor does it make any commitments for strong Agency intervention if such problems occur.

ANSWER:

The licensee is solely responsible to operate the nuclear power plants safely pursuant to their operating license. It has always been the NRC's responsibility to license and regulate nuclear facilities to protect public health and safety and the environment. The NRC staff takes that responsibility very seriously. Accordingly, the NRC staff is prepared to take any licensing or enforcement action, as permitted by our statutory authority, to ensure that public health and safety are maintained and not compromised by the operation of a nuclear facility. Our ability and willingness to exercise our authority, when conditions warrant, are evident in NRC actions relative to previous plant shutdowns at Browns Ferry, Peach Bottom, Calvert Cliffs, and Indian Point Unit 3. If our overall assessment of Salem's performance indicated that the potential existed to adversely compromise public health and safety, the NRC staff would act promptly to ensure that the facility was maintained in a shutdown condition until the issue was resolved. If warranted, the NRC staff would also impose the appropriate enforcement sanctions in accordance with the NRC Enforcement Policy as described by 10 CFR 2, Appendix C.

QUESTION 4. Why did the manufacturer recommend a change in the old material (17-4 PH) that had been used since the early 1980's?

ANSWER:

The licensee installed, as original equipment during plant construction, PORVs containing 17-4 Precipitation Hardened (PH) steel internals. In 1982, in response to NUREG-0737 Action Item II.D.1, the licensee replaced the existing plugs and stems at Unit 1 and Unit 2 with stellite clad 304 stainless steel plug and stem assemblies. In 1993, at Unit 1, the licensee removed the stellite clad 300 series stainless steel plugs, stems, and the 17-4 PH cages, and installed 420 stainless steel plugs with 316 stainless steel stems and 420 stainless steel cages. The licensee changed to the 420 stainless steel when the loop seals (a "U" shaped section of piping designed to maintain water against the valve seat) were removed from the inlet piping to the PORVs. This changed the operating environment of the valves from water to steam. The licensee, through conversations with the valve vendor, learned that the 420 stainless steel internals were available and this material provided improved wear characteristics. Although the existing internals were suitable for the changed environment, the licensee decided to upgrade the valve with the 420 stainless steel material.

QUESTION 5. What testing had been performed on the new material (420-series) to prove its reliability?

ANSWER:

The 420 stainless steel, as with 300 series stainless and 17-4 PH stainless, has been qualified to American Society for Testing Materials (ASTM) specifications. In addition, the valve manufacturer cites 20 years of successful use of 420 stainless steel in similar valve configurations used in fossil fuel plants. The manufacturer states that 420 stainless steel internals in this configuration have been used with good success in high pressure feed water systems. Further, the American Society of Mechanical Engineers (ASME) Code Case N-62-4 endorses the use of this material for valve internals.

QUESTION 6. In the aftermath of the failure of the new material, was the NRC database on equipment defects, required to be reported in accordance with 10 CFR 12(*sic*), reviewed for reports of similar problems in other PORV's in other reactors?

ANSWER:

Although scuffing and abrasion were apparent on the PORV trim packages (valve internals) removed from the PORVs (1PR-1 and 1PR-2), and the anti-rotational embossment on each respective plug element showed signs of cracking, the NRC staff does not consider that the device or the material failed. The fact that the device cycled over 200 times and performed the function for which it was designed is evidence of successful operation. Notwithstanding, NRC did review its database relative to PORV components and found no reportable defects of the type experienced in this case. NRC contacted Copes-Vulcan, Incorporated, the vendor of the PORVs used at Salem, and confirmed that no other licensees were distributed Type 420 trim package assemblies. The licensee has initiated a report in accordance with 10 CFR 21 relative to the cracking observed on both used and new Type 420 trim package assemblies.

QUESTION 7. Have other reactors currently using the new material in the PORV been notified of the Salem damage?

ANSWER:

The licensee notified other licensees of the wear that occurred in the PORVs via an electronic bulletin board system (NOTEPAD, which is a system maintained by the Institute of Nuclear Power Operations {INPO}). The NRC is preparing an Information Notice to inform other licensees of the Salem event and its implications.

QUESTION 8. Is this new material now regarded as inferior to the old material?

ANSWER:

Series 420 stainless steel is not considered inferior to other previously used materials. However, its application relative to the valve design used in this instance remains to be assessed. Scientists and engineers at the licensee's Maplewood Laboratories and other independent engineering organizations (e.g., Westinghouse and MPR Associates) are presently conducting metallurgical examinations, destructive and non-destructive testing, and engineering analyses (including computer based finite stress analysis) to evaluate the effect of the observed indications of cracks and wear on the operability of the PORVs under design conditions.

Based on the April 7, 1994 transient, PORVs with 420 stainless steel internals are capable of operating more than 200 times under steam and liquid conditions and remain functional despite indications of wear.

QUESTION 9. Will the NRC, or manufacturer, direct other licensees to change the internals, and what material will be recommended for installation?

ANSWER:

See response to Question 6.

QUESTION 10. PSE&G indicated that valve internal misalignment may have contributed to the failure of the valve. Was the valve installation technique a problem based on the manufacturer installation specifications or inadequate licensee quality control procedures? And what is being done to correct installation problems?

ANSWER:

Given the tight tolerances required for the valve internals, some scuffing of the stem, plug, and cage is not unexpected. However, the degree of abrasion observed in the case of the 1PR-1 and 1PR-2 valves exceeded what was expected by the licensee for cage-guided globe plug assemblies, even in view of the high number cycles that the valves experienced on April 7, 1994. Notwithstanding, as explained in the Response to Question 6, the valves did not fail and continued to function. The observed scuffing and abrasion (gouging), particularly as observed on the stem of 1PR-2, were of concern relative to the potential for galling sufficient to prevent functioning of the valve.

Though not conclusive, the most likely contributor to the condition of the valves was that the licensee s installation technique may not have been sufficient to reduce the potential for misalignment of the valve internals. While some minor out of tolerance condition (1.5 to 1.8 mils) was noted on the 1PR-2 cage, it is inconclusive whether the variance was due to machining tolerances or a consequence of the abrasion. It should be noted that 1PR-1 was observed to have less indication of wear than 1PR-2, and was found to be within the manufacturer's specified tolerances.

The installation technique was developed by the licensee, and independent of the vendor recommendations. The procedure specified preassembly of the plug assembly and packing in the bonnet in an effort to reduce radiation exposures to the workers. The level of quality control applied to the installation was minimal, but the requirements established by the licensee were followed. Quality control efforts were performed to confirm that the valve body and internals were free of foreign materials, and that the seal between the valve seating surface and the plug conformed to specifications. Specific quality control checks were not established to confirm alignment of the valve internals.

The installation procedure has now been revised to include steps that confirm the smooth operation of the valve as assembly progresses. At several steps, the valve assembly is stroked by hand to ensure that the trim package is functioning correctly as the parts are assembled in the body. Upon installation of the packing and final assembly, the valve unit is confirmed to operate correctly by stroking with the valve's air operator.

QUESTION 11. Regarding the PORV's in Unit 2, when was the NRC notified that the wrong material had been installed?

ANSWER:

The licensee informed the NRC inspectors that the wrong material had been installed on May 5, 1994.

QUESTION 12. Was this a result of operator notification or a result of my office contacting the NRC with this information?

ANSWER:

The finding was not the result of either operator notification or of contact with Senator Biden's office on May 13, 1994. The information was developed as a result of an NRC inquiry on May 4, 1994.

The following sequence of events was determined:

Initially, the licensee was in possession of six sets of Type 420 PORV trim packages (valve internals consisting of Type 316 stem, Type 420 plug, and Type 420 cage). During the last Unit 2 outage (2R7-Spring 1993), one pair of trim packages was expected to be installed in the 2PR-1 and 2PR-2 PORVs. Subsequently, during the last Unit 1 outage (1R11-Fall 1993), the second pair of trim packages was installed in 1PR-1 and 1PR-2 PORVs.

Following the April 7, 1994 Unit 1 trip, the trim packages for 1PR-1 and 1PR-2 PORVs were removed for examination. The valves were found to be scuffed and cracking was apparent on the embossment on the plug element at the anti-rotation pin. The licensee initially replaced the "damaged" PORV internals with what they believed were the third and last pair of Type 420 trim packages in their inventory. (NOTE: The replacement of PORV internals with Type 420 trim packages was consistent with a change to the Salem Updated Final Safety Analyses Report which described the PORV internals as Type 420.)

In response to questions from an NRC inspector concerning the status of other trim packages that remained in inventory, the licensee examined remaining spares on or about May 4, 1994, and determined that another pair of Type 420 trim packages was available in the licensee's warehouse. Examination of those parts revealed cracking on the embossment of one of the plug elements. The discovery of this pair of Type 420 trim packages (with the cracks) led the licensee to: (1) replace the Unit 1 PORV with different materials (i.e., Type 316 stem, Type 316 plug, and Type 17-4 PH cage); (2) and investigate the previous 2R7 outage relative to trim package installation. As a result of that investigation, the licensee determined that, due to errors in planning and communication, Type 420 trim packages had not been installed at Unit 2 as expected or planned. Review of the work package documentation revealed that trim packages having all 17-4 PH components were actually installed at Unit 2.

Subsequently, the licensee performed a safety evaluation that determined that trim packages containing 17-4 PH components were approved and acceptable for use.

QUESTION 13. Was the installation procedure that occurred last year documented, and did it reveal that the old material had been improperly reinstalled?

ANSWER:

The installation of valve internals at Salem Unit 2 in April 1993 was documented in the Work Order package, and it revealed that 17-4 PH internals were installed. The Design Change Package called for the installation of a 420 stainless steel plug with a 316 stainless steel stem and a 420 stainless steel cage.

QUESTION 14. Your staff indicated in a conference call with my staff that a representative from the manufacturer, Copes-Vulcan, was present at the installation of the material in the Unit 2 PORV's. Did the manufacturer's representative certify in any documentation the content of the material that had been installed, and, if so, what material was described?

ANSWER:

The licensee informed the NRC inspectors that no such vendor certification documentation exists or was expected. The Copes-Vulcan representative's presence was to assist in the installation. The licensee is responsible for assuring the quality of the installation.

QUESTION 15. The NRC indicates in its status report (page 22) that it has concluded that Unit 2 PORVs "are acceptable for continued operation of that unit." Is this conclusion based on assurances from the manufacturer, or on an independent evaluation?

ANSWER:

This conclusion is based on independent NRC review of the validity of evaluations performed by the licensee and vendor.

QUESTION 16. While stating that, "each of the licensee's proposals appears to have merit, the effectiveness of these modifications remains to be demonstrated," the NRC concludes, in an apparent contradiction, that the "plant design and the procedures that the licensee has (or will have) in place assure that the loss of circulating water to the main condenser will not challenge the safety of the nuclear plant."

If the licensee and/or NRC are not able to provide evidence that the new and proposed modifications will be effective, on what assurance is this conclusion of "safety" based?

ANSWER:

These statements do not appear to us to be in contradiction. While the licensee's planned design changes to the circulating water intake structure (relative to modification of the traveling screens to permit higher rotational speeds, trash rake and screen wash pump enhancements, and other possible improvements), may prove more effective relative to handling heavy grass intrusion conditions, the safety of the nuclear plant is not dependent on the success of these design changes.

The purpose of the circulating water system is to provide cooling for the main condenser, a non-nuclear and non-safety related component. Loss or reduction of circulating water to the main condenser (whether due to grass intrusion, loss of power to the circulating water pumps, or any other condition) could result in turbine trip and possible reactor trip; and might also result in the loss of the main condenser as an effective heat sink for the turbine. While such conditions are obviously not desirable, adverse situations involving the effectiveness of the main condenser and the consequent effect on turbine and reactor systems were anticipated, factored into the design of the facility, and are analyzed conditions with acceptable outcomes.

Notwithstanding this demonstrated ability, grass intrusion appears to be developing as a phenomenon that is continuing to impact the normal operation of the Salem facilities. As a result, it is incumbent on the licensee to assess the situation and effect changes, as necessary, to reduce challenges to, and reliance on, plant design and system function. In the short-term, the licensee has amended its procedures to make it more likely that a turbine trip will be initiated if difficulty with the circulating water system is experienced. In the longer term, if the planned improvements to the circulating water intake structure prove effective in reducing, if not eliminating, the effects of grass intrusion, even more margin will be gained. Accordingly, it is our intent to closely follow the licensee's efforts to deal with this situation.

QUESTION 17. Nevertheless, the NRC concludes that the "near-term and long-term actions initiated by the licensee appear to be sufficient to cause improvement if management maintains their commitment to the program."

Given the history of Salem management failures and PSE&G's repeated promises of improved performance, I am neither comforted nor encouraged by the NRC's unexplained yet enduring confidence in PSE&G's efforts to improve management effectiveness.

ANSWER:

(See response to Question 1 for additional details.) The NRC recognizes that licensee management effectiveness is essential to the success of any performance improvement endeavor. The results of licensee performance improvement efforts may not be immediately apparent. They are expected to be evident and realized in the long-term relative to performance indicators, including:

A. Reduction in:
   1. automatic scrams (trips) while critical;
   2. forced outage rate;
   3. problems associated with personnel errors (operators and others);
   4. significant events, including occurrences that require AIT involvement;
   5. inspection findings involving adherence to procedures;

6. problems associated with maintenance, installation, or fabrication;
7. problems associated with design or engineering;
8. recurrent violations of a similar nature; and,

B. Improvement in overall reliability and capacity for each Salem unit.

Each of these indicators is being monitored. Our continuing qualified confidence in the licensee is based on the following:

1. In 1993, PSE&G acknowledged for the first time weaknesses in management effectiveness and the need to achieve performance improvements. A state of denial existed previously. Thus, PSE&G's acknowledgement of management deficiencies was the first step in correcting problems.

2. The licensee previously recognized the vulnerability of certain aspects of the Salem design and processes and took aggressive remedial action. Specifically, in 1989 PSE&G initiated a program for overall plant revitalization, and was successful in the planning and execution of the effort. Significant material condition improvements were completed (including several design changes and service water system replacement), measurable improvements were made in material maintenance (e.g., leak reduction, painting, repair of insulation, component labeling, and overall housekeeping), all procedures were reviewed and upgraded, and corrective and planned maintenance backlogs were reduced significantly.

3. The NRC staff has reviewed licensee efforts to identify and assess specific areas that require improvement. The NRC staff has also examined their plan for improvement and are satisfied with the scope of the effort. The NRC staff believes that the licensee is committed to carrying out the plan in an aggressive manner. Significant changes in overall leadership, supervision, and organizational structure are already evident.

4. NRC has reviewed PSE&G efforts and progress through inspections and meetings with the licensee to keep informed of site activities and progress toward goals. On the other hand, the staff is aware that many of these results are in the nature of future promises, not demonstrated improvements, and will require continued close monitoring.

FOLLOWING ITEMS ARE FROM YOUR LETTER DATED MAY 11, 1994

QUESTION 18. I request that the NRC impose the maximum fine allowable on PSE&G.

ANSWER:

With regard to potential enforcement action related to the April 7th event, the NRC staff is in the process of reviewing all the facts concerning what happened. It will compare those activities to the requirements of the Code of Federal Regulations and the license held by PSE&G to determine what violations may have occurred. If appropriate, the NRC staff will call an enforcement conference with the licensee to fully understand their views on what happened and to give them the opportunity to present any facts they consider germane to the issues. Following the enforcement conference, the NRC staff will propose enforcement sanctions if appropriate. This enforcement activity will be initiated immediately upon completion of the AIT report.

QUESTION 19. The extent of the clogging problems and the adequacy of the current system to handle intake demand and river grass clogging in the future must be resolved. If the system is deemed incapable of handling the river grass problem, what are the technical solutions and when can they be implemented?

ANSWER.

The licensee's short- and long-term actions to cope with the marsh grass and the NRC staff's evaluation of the adequacy of these actions are described in Enclosure 2, Item A.9. and in Response to Question 16. Modification of the screens to provide for increased grass elimination is expected to be implemented June 1995 and June 1996, respectively, for Units 1 & 2 at Salem. This schedule is based on parts availability from the vendor and successful demonstration of the screens to mitigate the impact on fish satisfactorily in accordance with the licensee's Environmental Permit.

The service water intakes were not affected by excessive grass intrusion during or previous to the April 7th event. Consequently, the functioning of safety-related systems dependent on the service water system have not been compromised as a result of the grass intrusion problems at the circulating water intake structure.

The Augmented Inspection Team inspected the conditions in the immediate area of the service water intakes and determined that the system was not being threatened by the grass intrusion in the same manner as the circulating water system, due to relative location, design, and the significantly less water volume that is required by the system, as compared to the circulating water system. The larger volume drawn into the circulating water system has the effect of conducting more grass into the pump intake structure. Nonetheless, the NRC staff believes that threat to the non-safety related circulating pump intakes should be ameliorated to reduce unnecessary plant trips and operator challenges.

QUESTION 20. The cause of the safety valve wear must be determined since the reactor core could have overheated if the valves had failed.

ANSWER:

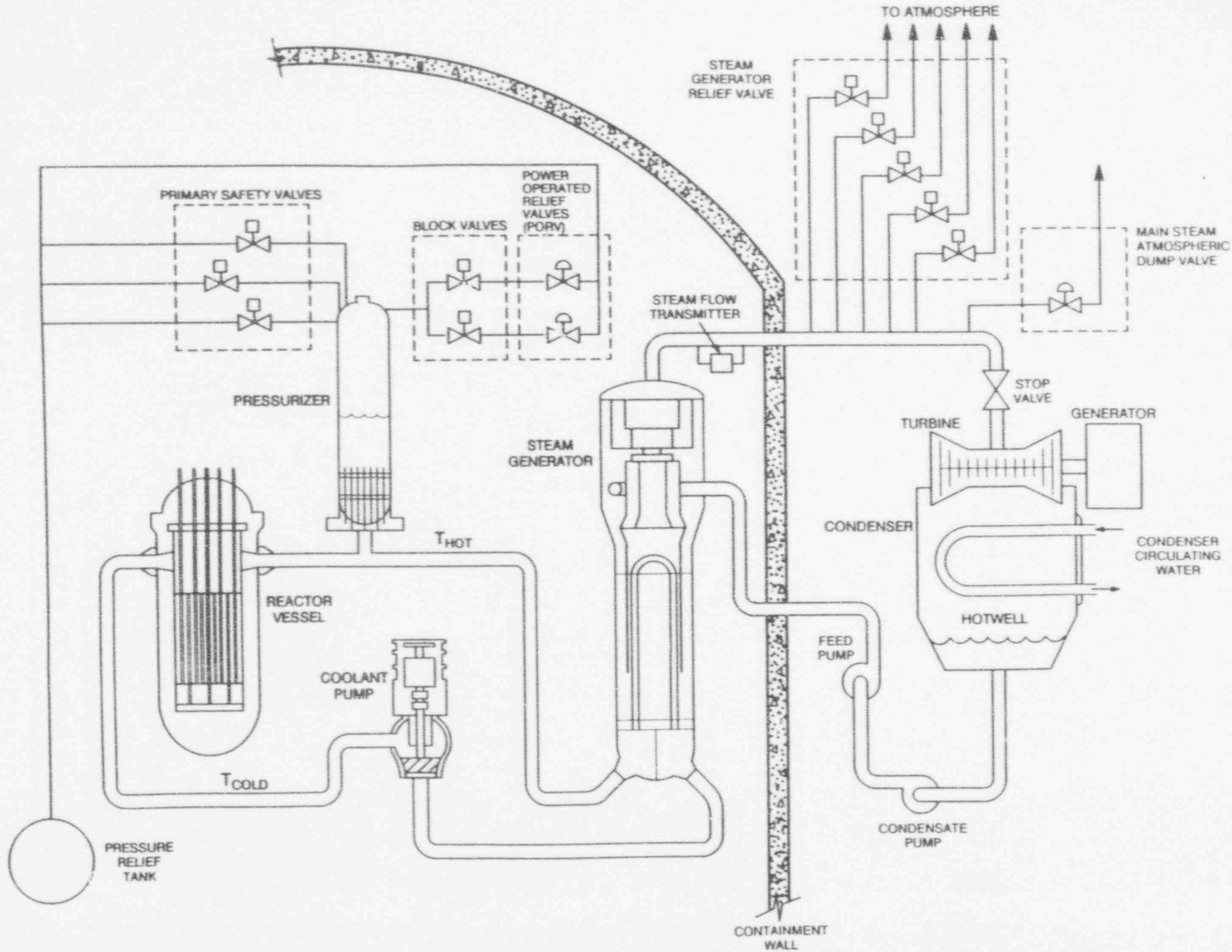
Responses to Questions 8 and 10 pertain. Based on the April 7, 1994 transient, the PORVs functioned as designed while sustaining some wear and galling in the process. However, while proper PORV operation is always preferable for transient control, failure of the valves to function as designed is an anticipated possibility. Accordingly, a redundant and diverse system of block valves is available to isolate the reactor coolant system if the PORV were to fail open. Overheating of the reactor is not an expected outcome as long as Safety Injection systems are available. The NRC staff will continue to followup on PORV material and design issues to ensure effective generic resolution.

QUESTION 21. The public needs to know if the NRC can, and will, correct the management and system failures that are real dangers at Salem.

ANSWER:

The NRC will take the appropriate actions to ensure the health and safety of the public at the Salem facility. See Response to Question 3.

SALEM SYSTEMS



ENCLOSURE 2

STATUS OF MAJOR ISSUES AFFECTING RESTART ACTIVITIES AT SALEM UNIT 1

The following issues have been evaluated by NRC staff including (1) assessment of licensee submittals dated April 25, April 29, May 10 and May 13, 1994, (2) independent inspection of licensee activities and (3) discussion with appropriate licensee representatives.

A. Equipment

1. Pressurizer Power Operated Relief Valve (PORV) Operability

Issue: As a result of the initial safety injection on April 7, the reactor coolant system (RCS) filled with water. Without the normal pressurizer steam space to dampen pressure excursions, the continued injection from the first and second automatic safety injection actuations resulted in repeated actuations of the PORVs to limit RCS pressure. As a result of the challenge to the PORVs, the NRC AIT questioned whether any damage to the valves had occurred.

PSE&G Response: The licensee removed the PORV internals for inspection. The results of the licensee investigation showed that excessive wear was exhibited on the internals of one PORV and slight cracking on the internals of both PORVs. The licensee identified the source of the cracking at the boss used for the stem to plug interface in the valves to be intergranular stress corrosion cracking (IGSCC), compounded by the stress induced from the different thermal expansion characteristics of the valve internal materials. The cracking occurred where the stem of the valve, which was made of a 300-series stainless steel, was pinned through the boss to the plug of the valve, which was made of a 400-series stainless steel. PSE&G replaced the internal parts of the Unit 1 pressurizer power-operated relief valves (PORVs), 1PR-1 and 1PR-2, with new internals: a valve stem and plug made of 300-series stainless steel and a valve cage made of 17-4 PH stainless steel. The new stem and plug have essentially the same thermal expansion characteristics, which will relieve the stresses which contributed to the observed cracking. Further, a new design of the valve eliminates the boss used in the previous design and provides a more rigid stem to plug interface. *Other factors that promote the IGSCC* include the preload stresses that are applied when the valve internals are assembled by the manufacturer. In fact, similar cracking, though not as prominent, was observed on other valve internals that the licensee maintained as new spares. Consequently, the licensee has initiated action to report this apparent equipment defect in accordance with 10 CFR 21.

The licensee also modified the procedures used to assemble and install the PORVs in order to prevent potential valve internal misalignment. PSE&G believed the misalignment, which was due to valve installation technique, contributed to the scuffing and galling observed on the valve internals after the event.

NRC Followup: The NRC reviewed and discussed with licensee engineering the results of vendor analysis of the affected PORVs. The inspectors subsequently reviewed the PSE&G design change package and accompanying 10CFR50.59 safety evaluation for the installation of the new valve internals. The inspectors determined that the new material combination, which has been used in this application before, and the new installation procedure adequately resolve the PORV operability concerns.

2. Pressurizer Safety Relief Valves

Issue: As a result of the challenge to the PORVs discussed above, the NRC AIT also questioned whether any damage to the safety valves had occurred.

PSE&G Response: PSE&G took steps to assure the operability of the pressurizer safety relief valves (1PR-3, 1PR-4 and 1PR-5). These steps included visual inspection and non-destructive examination of the valves and lift setpoint and seat leakage testing by a vendor, Wyle Laboratories. 1PR-3 and 1PR-5 tested satisfactorily. 1PR-4 exhibited some seat leakage at 90% of the setpoint and lifted at a slightly higher setpoint. Wyle lightly lapped the seat of the 1PR-4, adjusted the setpoint, and the valve retested satisfactorily.

NRC Followup: The NRC discussed the licensee test plan with PSE&G engineering, reviewed the test results achieved by Wyle Labs, and compared the performance of the 1PR-3, 1PR-4 and 1PR-5 with other comparable industry results. The inspectors determined that PSE&G's actions had been appropriate to assure that the pressurizer safety relief valves were operable prior to restart of Unit 1.

3. Pressurizer PORV and Safety Relief Valve Piping and Supports

Issue: Following the Unit 1 trip, the pressurizer filled to a water solid condition, which resulted in operation of the PORVs and subsequent discharge of fluid from the pressurizer to the pressurizer relief tank. The repeated cycling of the PORVs, and the associated repeated discharge of fluid, prompted the NRC to question the structural integrity of the affected PORV piping and supports.

PSE&G Response: To assess the structural integrity of the PORV piping and supports, the licensee performed an engineering evaluation (S-1-RC-MEE-0898) and several system walkdowns. The engineering evaluation referenced numerous calculations, assessments, and additional engineering evaluations performed both prior to and following the event. The licensee's engineering analysis enveloped the effects on the system caused by the events of April 7. Based on system walkdown observations, the licensee concluded that there was no observable damage to piping or their supports due to the repeated discharge of fluid through the PORVs.

NRC Followup: The NRC reviewed the details of the system walkdown, and the engineering evaluation (S-1-RC-MEE-0898). Based on these reviews, the NRC concluded that the questions on the structural integrity of the affected PORV piping and supports had been adequately resolved.

4. Steam Flow Transmitter Response to Turbine Trip

Issue: The initial Solid State Protection System (SSPS) actuation resulted from the coincidence of low RCS temperature (due to operator error) and a spurious high steam flow signal. The spurious high steam flow condition coincident with the low primary coolant temperature. The apparent high steam flow condition was previously identified by the licensee, but its cause had been attributed to a combination of the SSPS logic (a reactor trip automatically reduces the high steam flow setpoint from 110% to 40% of rated steam flow) and the actual decay in steam flow following a reactor-turbine trip.

PSE&G Response: Upon closer analysis following the event, PSE&G identified that the actual cause of the indicated high steam flow signal following a turbine trip corresponded to the pressure wave initiated by the closure of the turbine stop valves, that appeared to the main steam flow transmitter as a short duration high steam flow condition. The licensee subsequently installed a resistive-capacitive network to decrease steam flow instrument sensitivity to short-duration steam flow signals, while not preventing the instrument from properly sensing a true high steam flow condition.

NRC Followup: The NRC reviewed the licensee modification package and concluded that the transmitter time delay circuit is an appropriate means of resolving the spurious steam signal phenomenon without compromising the safety function of the steam flow transmitter.

5. Steam Flow Instrument Drift

Issue: Steam flow instrument calibration at Salem station has been known to change with time [drift] since initial plant operation. As a result, indicated steam flow, for the same power level, increases with time at power and decreases with time after a plant trip or shutdown. Periodic re-calibration had been required to make indicated steam flow equal 100% at 100% power. This phenomenon had caused, along with process noise, spurious frequent tripping of steam flow bistables and logic input relays. Although this phenomena did not appear to play a direct role in the event, probably due to recent Unit 1 modifications, the historic frequent tripping of the bistable may have contributed to premature deterioration of the safety injection logic relays and the different responses of the safety injection logic experienced during the event.

PSE&G Response: The licensee stated that the cause of the instrument drift was entrained gases in sensing lines leading to the instruments, which has been supported by two consultants. In order to correct this problem they have replaced the instrument sensing lines with larger tubing, larger condensing pots, reoriented the lines to a consistent downward slope and have removed insulation from sensing lines and condensing pots to promote condensation and facilitate escape of noncondensible gasses. This modification was installed in Unit 1 last outage [Nov '93-Feb '94] and will be installed at Unit 2 the next outage [Oct '94]. Results from operation at Unit 1 since startup have been inconclusive. Since the unit has not been maintained at full power in any period sufficient to verify the effectiveness of the modifications. However, no re-calibrations have been required since the modification was installed. Additional plant operating time at full power will be needed to determine if the modification has been effective in reducing or eliminating the "drift".

The licensee has a surveillance procedure in place to monitor steam flow instrument calibration at both units. The procedure includes acceptance criteria for identifying unacceptable drift. The procedure identifies when recalibration should be accomplished.

Addition of the resistive-capacitive network to resolve the reaction to short duration pressure pulses will also reduce the sensitivity to process noise signals as discussed in item 4 above.

Licensee calculations show that calibration adjustments have not violated any technical specification requirements.

The licensee acknowledges the frequent tripping of the bistables, but believes there is insufficient data to support a cause/effect relationship between spurious frequent tripping (chatter) of logic relays and the difference in the logic trains' response during the event.

NRC Followup: NRC staff has reviewed the licensee response to T. T. Martin dated May 13, 1994 concerning steam flow instrument drift. The letter includes details on the licensee monitoring program and associated calibration adjustments made to ensure steam flow set point values remain within technical specification required values.

The NRC staff concluded that the steam flow instrument drift should be minimized by the condensing pot and sensing line modifications installed at unit 1 and planned for unit 2. The procedure for monitoring steam flow instrument calibration has been reviewed and found to be acceptable.

There is not a preponderance of evidence to prove that there is a nexus between steam flow instrument drift and associated input relay chatter and apparent differences in steam flow safety injection logic relays. The NRC staff has also concluded that the different responses of the 'A' and 'B' safety injection logic relays are explainable as normal variations in time response of these relays.

Installation of a resistance-capacitance circuit in the steam flow instrument measuring circuit should minimize the steam flow instrument's sensitivity to short duration steam pressure pulses as well as process noise. This circuit will not degrade the response of the instrumentation to accident conditions.

Based on the licensee monitoring program in place to ensure instrument drift does not result in the violation of technical specification limits, the safety function of the instrumentation will be assured.

6. Solid State Protection System/High Steam Flow Input Relays

Issue: Following the reactor trip and initial automatic safety injection (SI) of April 7, operators recognized that only train A of the solid state protection system (SSPS) had actuated. Several actions controlled by SSPS train A failed to go to completion resulting in several components not operating as expected. The apparent disagreement between the SI logic trains was not provided for in the EOPs, and operator response to the event was delayed as they manually aligned the two trains and the affected components.

PSE&G Response: Due to the different responses of train A and train B of the solid state protection system (SSPS) to the event, PSE&G conducted further examination and testing of SSPS components. The licensee concluded that the very short duration of the high steam flow signal explained why only train A of SSPS initiated. Also, the various components within a SSPS train are operated by different latching and seal-in relays, that also have different response times. This fact, along with the short duration high steam flow signal, explains why not all actions of train A (main steam and feedwater isolation) went to completion. While the licensee testing showed a difference between the time response of the two SSPS trains and found discoloration in some SSPS relays, the licensee determined that both channels operated within the SSPS design and Technical Specification requirements. Further testing results confirmed that had an accident condition existed, both SSPS trains would have actuated and all actions would have gone to completion. The licensee nonetheless replaced the high steam flow impact relays, and subsequent testing showed the differences between the channel time responses had been reduced. PSE&G provided additional guidance to plant operators on manual actions to be taken in the event of different responses of the two trains of SSPS.

NRC Followup: The NRC staff monitored the licensee investigation, reviewed the initial test data, and observed portions of the licensee follow-up testing of the SSPS relays. The inspectors determined that the licensee's root cause was acceptable. The staff also determined that the replacement of certain relays was prudent, and that the guidance provided to the operators was appropriate.

7. Main Steam Atmospheric Relief Valve (MS-10) Controller

Issue: The MS-10s did not automatically respond to and control high steam generator pressure on April 7, 1994. Following the plant trip and initial safety injection, the reactor coolant system (RCS) temperature increased as a result of core decay heat and reactor coolant pump heat. This RCS heatup, and the corresponding increase in steam generator pressures, was not recognized by the Salem operators. Steam generator pressures increased above the setpoint of the atmospheric relief valves, because of a failure of the MS-10 controllers to promptly respond. Consequently, the steam generator code safety valve lifted. The steam release through the safety valve caused a cooldown of the reactor coolant system. The cooldown of the RCS resulted in a rapid pressure decrease that initiated the second automatic safety injection due to an actual low pressurizer pressure condition.

PSE&G Response: During normal plant operation the MS-10 controllers provide a constant close signal to the valves since normal steam pressure is much lower than the valve opening setpoint. This results in the saturation of the controller circuitry. As a result, the automatic opening of the valves is delayed during actual conditions of high steam generator pressure by an amount of time it takes to clear the saturated condition. The controller was modified shortly after initial startup of the Salem unit to prevent inadvertent opening of MS-10. PSE&G has now implemented a design change to install a discharge path for the capacitor in the control circuit which was susceptible to the saturation phenomenon. This design change re-installed the part of the circuit which the licensee had previously removed. The controller gain and reset times have also been changed to further improve the controller time response to a rapidly increasing steam generator pressure condition and avoid inadvertent openings of MS-10 valves.

NRC Followup: The NRC reviewed the design change package which implemented the changes in the MS-10 controller circuit, discussed the modification with licensee engineering, and concluded that the re-installation of the capacitor discharge path would provide better automatic control of steam generator pressure during transient plant conditions. The inspectors will observe licensee testing of this modification during plant heat-up.

8. Rod Control System Operation

Issue: The rod control system was being operated in the manual mode due to ongoing system troubleshooting and operator uncertainty with regard to the system operability in the automatic mode. If the system had been operated in the automatic mode the excessive reactor coolant system cooldown may have been minimized or avoided.

PSE&G Response: At the time of the event, the rod control system deficiencies had been resolved with the exception of monitoring a system isolator to determine if a drifting problem had been corrected. Final system testing was scheduled the day of the event. Following the event troubleshooting determined that the automatic mode was fully operable.

NRC Followup: The AIT reviewed the results of the troubleshooting and testing of the rod control system and determined that PSE&G had adequately corrected the system deficiencies to permit operation of the rod control system in the automatic mode.

9. Circulating Water Intake

Issue: Marsh grass accumulates in the Delaware River and is drawn into the circulating water system by the circulating water pumps. When the grass quantities become large they tax the traveling screens' ability to remove the grass as fast as it accumulates, clogs the intake flow path and causes loss of cooling to the main condenser. Loss of cooling to the condenser requires reduction of plant load, or plant shutdown.

PSE&G Response: The licensee response is divided into short and long term actions. In the short term the licensee has assigned maintenance and operations personnel to the circulating water intake structure to maintain and clean the screens. Prior to the last refueling outage the licensee installed low pressure headers to clear siltation and improve screen wash spray nozzle effectiveness. Screen wash control panels and instrumentation were replaced or refurbished. Procedural enhancements have been made since the event to give operators more guidance on responses to an influx of marsh grass. Criteria for initiating a manual reactor and/or turbine trip have been included. The density of grass loading is currently showing a decreasing trend. The major impact of marsh grass is expected to be over for 1994.

Long term enhancements include modifications to the traveling screens to permit higher speeds. The higher screen speed will increase the grass removal capability of the screens and lessen the probability of loss of circulating water flow due to grass intrusion. Higher speeds will be achieved by replacing the screen baskets with lighter material and replacing the drive motors/gearing and controls for higher speeds. These modifications are expected to be completed by June 1995 for one Salem unit and by June 1996 for the other unit.

In addition, the existing trash rakes, which are positioned in front of the screens will be replaced to enhance trash rack cleaning and levelize intake velocity profiles. This modification is expected to be completed in October 1994.

The licensee plans to replace two screen wash pumps [there are 4 per unit] with pumps of upgraded materials and lower maintenance requirements. The licensee then intends to evaluate the screen wash system to determine optimal pump operating range, and to monitor the system effectiveness. This modification is expected to be completed in October 1994. Pending the results of the experience with these two pumps, the remaining 6 pumps may be replaced with the new design.

PSE&G plans to make other modifications, including spray nozzle additions and re-orientations, internal piping modifications and new designed seals between stationary and moving screen components to improve grass handling capabilities. The implementation schedule for these modifications has not been established.

The licensee is also reviewing the circulating water system, the grass movements and loadings, and will consider various approaches, such as physical barriers in the river to improve the ability to mitigate marsh grass and removal of grass by dredging. No schedule for completion of these studies has been provided.

NRC Followup: Long and short term plans for coping with the grass problem have been reviewed by the staff and discussed with the licensee. Long term plans appear to be aimed at coping with potentially severe grass intrusions. Each of the licensee's proposals appears to have merit. The effectiveness of these modifications remain to be shown through experience in the future.

Operators have been trained to deal effectively with severe intrusions of marsh grass. In addition, procedures have been revised and equipment has been modified to address grass intrusion.

The NRC has reviewed the licensee's procedures and training of operators for coping with grass intrusions. Evaluation of these procedures is discussed in Sections B.2 and 3 below. The plant has been designed and the procedures that the licensee has put in place will accommodate loss of circulating water to the main condenser, regardless of cause.

B. Procedure Improvements

1. SC.OP-DD.ZZ-OD22(Z), "Control Room Reading Sheet Mode 5 Through 6"

Issue: Following the plant cooldown subsequent to the April 7 events, the NRC identified the Salem Unit 1 reactor vessel level indication system (RVLIS) indicated reactor vessel water level at 93%. When questioned, the Salem control room operators could not explain the significance of the indication, nor were they required to monitor this indication in the current plant operating mode.

PSE&G Response: RVLIS values are now logged when a unit is in Mode 5 (Cold Shutdown) or Mode 6 (Refueling), and the procedure requires response actions when the indicated level is below the minimum value specified in the procedure.

NRC Followup: The NRC staff reviewed the procedure change, discussed the change with Operations management, interviewed operators to assess their knowledge of the new requirements, and observed operator training in the

Salem simulator. The inspectors concluded this action addressed the NRC-identified deficiency in Salem control room operator use and application of RVLIS indication when the plant is in Mode 5 or 6.

2. S1(2),OP-AB.COND-0001(Q), "Loss of Condenser Vacuum"

Issue: During the rapid downpower conducted by Salem Unit 1 operators immediately preceding the April 7 reactor trip, the operators took extraordinary steps to attempt to keep the unit on line while dealing with the loss of circulating water pumps and main condenser cooling. The NRC determined that a lack of procedural guidance existed for operators on when to trip the turbine and/or reactor during low power operation.

PSE&G Response: The procedure now specifies actions to trip the reactor and/or turbine as a specific function of primary coolant temperature, condenser vacuum, condenser back pressure, reactor power, and turbine power conditions.

NRC Followup: NRC reviewed the procedure change and noted that the specific guidance provided in the procedure now adequately directs operators on what the necessary plant conditions are to remove certain components from service. The inspectors confirmed operator awareness of the new requirements through operator interviews and through observation of simulator training on the new procedure.

3. S1(2).OP-AB.CW-0001(Q), "Circulating Water System Malfunction"
S1(2).OP-SO.CW-0001(Z), "Circulating Water Pump Operation"

Issue: The rapid downpower maneuver performed by Salem Unit 1 operators on April 7 was necessitated by the rapid loss of the unit circulating water pumps due to river grass accumulation and the resultant loss of main condenser cooling. The NRC determined that the operators lacked procedural guidance on what specific actions were required when dealing with the effects of river grass on circulating water pumps.

PSE&G Response: These procedures now specify operator actions for the condition when two or more circulating water pumps are out of service and identify actions for operators to take in the case of abnormal condenser vacuum situations.

NRC Followup: The NRC reviewed the procedure change and operator knowledge of the new instructions and observed their practice in the Salem simulator. The inspectors determined that the new procedures provide the proper guidance to the plant operators for the loss of circulating water pumps.

4. S1(2).OP-AB.TRB-0001(Q), "Turbine Trip Below P-9"

Issue: During the April 7 downpower maneuver, Salem operators reduced reactor and turbine power at different rates. The resulting power mismatch resulted in the overcooling of the primary coolant system and the subsequent need for the operator to withdraw control rods, which led to the reactor trip. The operators did not have guidance to manually trip the turbine off-line to restore primary coolant temperature.

PSE&G Response: The turbine trip procedure now incorporates guidance for operator response to inadvertent or excessive primary coolant cooldown conditions. The new guidance provides for manually tripping the turbine under certain conditions in order to prevent unnecessary challenges to the reactor and primary coolant system.

NRC Followup: The NRC reviewed the procedure change and noted that the guidance for operator action relative to a manual trip of the turbine was appropriate and properly addressed the concerns of the event. The inspectors subsequently verified, through interviews, adequate operator knowledge of the new guidance and observed satisfactory performance of the new procedure at the Salem simulator.

5. S1(2).OP-IO.ZZ-0004(Q), "Power Operation"

Issue: The power mismatch between the Salem Unit 1 reactor and turbine which occurred on April 7 resulted in the overcooling of the primary coolant system to the point where coolant temperature went below the minimum temperature for criticality as specified in the unit Technical Specifications. The operators did not have adequate procedure guidance for required action when plant operation did not meet the Technical Specification requirement for minimum temperature for criticality.

PSE&G Response: The procedure for power operation of the Salem units now has specific directions for maintaining reactor coolant temperature greater than, or equal to, the minimum temperature for criticality. If this temperature cannot be maintained above the minimum temperature for criticality, operator. are required to trip the reactor.

NRC Followup: The NRC reviewed the new guidance and specific direction provided in the procedure change for maintaining primary coolant temperature above the Technical Specification limit. The inspectors conducted operator interviews and observed operator simulator training and concluded that the procedure change and operator training adequately addressed the issue.

6. Emergency Operating Procedures (EOPs)

Issue: During the operator response to the reactor trip and multiple safety injections on April 7, the operators encountered situations where the EOPs did not provide specific guidance or direction. These situations included:

- Resolution of solid state protection system logic train disagreement,
- Manual operation of the steam generator atmospheric relief valves to control steam generator pressure and primary coolant system (RCS) heatup, and
- Prevention of solid RCS conditions and, if they do occur, a plant cooldown under those conditions.

PSE&G Response: PSE&G is pursuing long term changes affecting the EOPs and Critical Safety Function Status Trees (CSFSTs), working in conjunction with the Westinghouse Owners Group. In the interim, the licensee has provided additional guidance concerning these situations to operators in an Operations Department Information Directive (ID) and in a simulator training lesson plan which addresses the entire April 7 event. In response to the above situations, the ID provides guidance to operators on: when a safety injection train disagreement is noted, to manually initiate a safety injection actuation for the train that did not automatically actuate; following a reactor trip, to take manual control of the MS-10s at any time steam generator pressure is at or above the valve setpoint with no apparent valve motion; and, during EOP use after initiation of CSFSTs, and if no higher path conditions exist, the Shift Technical Advisor is to refer to Yellow Path Restoration Procedures to monitor RCS parameters and other indications in order to detect or prevent unexpected plant conditions, such as solid RCS conditions. Reading, discussing and understanding the ID, and instruction in the simulator lesson plan, were required of all licensed and non-licensed operators prior to their assuming a watch.

NRC Followup: The NRC discussed the considered EOP changes with Salem Operations Department management, reviewed the guidance provided in the department's ID and the simulator training lesson plan, and observed the training of operators using the lesson plan at the simulator. The inspectors verified operator knowledge of the new guidance through interviews of several operators from different shift crews. The inspectors concluded that the guidance provided in the ID and the training provided at the simulator were an effective means of resolving the evidenced EOP concerns.

C. Salem Operating Crew Shift Composition and Shift Management Responsibilities

Issue: In addition to the above identified equipment and procedure issues, the NRC identified several areas in which Salem control room operator performance and resource management affected the response to the event. These areas included:

- Maintaining adequate control room staffing,
- Control room crew communications,
- Prioritization of personnel assignments and use of additional licensed operating personnel, and
- Scope of Senior Nuclear Shift Supervisor involvement in Emergency Operating Procedure (EOP) operations.

PSE&G Response: PSE&G determined their operational experience established a level of confidence in the ability of the presently required shift crew to successfully operate the Salem facility. The licensee, however, also identified a number of root causes and causal factors for the event that were associated with resource utilization, encompassing the above areas identified by the NRC.

The licensee responded to the identified concerns through the previously noted Salem Operations Department Information Directive (ID) and simulator training. All Operations crew shifts received the simulator training on the lesson plan derived from the event, and all shifts were required to read, discuss and understand the directions provided in ID prior to resuming a watch position.

NRC Followup: The NRC reviewed and inspected the above procedure changes and training enhancements. The review included interviews with licensed operators, discussions with Operations Management, and observation of crew training at the Salem simulator. The inspectors concluded that the changes made to the noted procedures, the additional training supplied to licensed operators, and the guidance provided by management to the operators effectively addressed the personnel performance issues identified as a result of the event.

D. Unit 2 Consideration

Issue: Considering the procedure changes, training and hardware modifications identified from the event for implementation at Unit 1, the NRC was questioned what short and long term corrective actions were being implemented at Unit 2.

PSE&G Response: As a result of the event at Salem Unit 1, operator retraining and procedural enhancements were implemented at Unit 1 and 2. Design modifications were performed at Unit 1 and are planned for Unit 2 no later than the next refueling outage, that begins October 15, 1994.

Operators were given additional training and written guidance on response to marsh grass, downpower and low power operations, RCS temperature control, control room resource management and proper actions to be taken for solid state protection system train disagreement. Operators have been trained, prior to this event, on how to cope with MS-10 controller malfunctions and how to operate the system in manual. They were given additional training following the event.

The Unit 2 PORV internals are of a different material, 17-4 PH stainless steel, than those at Unit 1. The 17-4 PH internals are approved for this use by the vendor and are similar to those which were installed in both Unit 1 and Unit 2 at the time of initial operation. Finally, the licensee has not experienced any problems with this material to date, and believes continued use until the next refueling outage is justified.

The licensee believes that delaying implementation of the hardware fixes to an outage of sufficient duration, but not later than the next refueling outage, currently scheduled for October 15, 1994, is appropriate.

NRC Followup: The NRC reviewed the 10CFR50.59 safety evaluation for continued operation with the Unit 2 PORVs in the as-is condition. The NRC verified that the internals of the Unit 2 PORVs were replaced with components made from 17-4 PH stainless steel. In addition, the NRC confirmed that the material changes for the internals were approved by the PORV vendor. The PORVs will be inspected and a design change considered during the next refueling outage. The inspectors concluded that the Unit 2 PORVs are acceptable for continued operation of that unit.

The NRC staff has reviewed the planned modifications (MS-10 control circuit and steam flow circuit time delay) at Unit 2 and concluded that compensatory measures provided by improved procedures and operator training are acceptable until the next outage of sufficient duration to install the modifications.

What is our opinion of the need for the other hardware changes?

The inspectors have reviewed procedures and training related to coping with rapid power reductions, use of reactor vessel level instrumentation, manual operation of MS-10s, RCS temperature control, logic train disagreement, control of noncondensible gasses in the vessel and cooldown of a solid RCS. With these procedures in place and the associated training completed, operation of Unit 2 until October 15, 1994 is considered acceptable.

E. Management Effectiveness in Resolving Long-Standing Problems Affecting Performance at Salem

Issue: Since the November 1991 Turbine-Generator failure event, which resulted in review by an Augmented Inspection Team, PSE&G has continued to experience recurring operational, design, and maintenance-related problems. Contributing causes to these occurrences have been weaknesses in management and oversight of activities, inadequate root cause analysis, failure to follow procedures, personnel error, ineffective approach to resolution of problems, and insufficient corrective actions. While none of the events have adversely affected public health and safety, the licensee's apparent inability to demonstrate improving performance has been a continuing concern to the NRC.

PSE&G Response: In their May 13, 1993, letter, PSE&G noted that they have established plans and completed actions relative to: (1) Salem Performance Improvement; (2) Quality Assurance/Nuclear Safety Review Oversight; and (3) Augmented Independent Oversight.

Prior to the event PSE&G management had already implemented significant material conditions upgrades at Salem, including design changes that directly improved control room operations. Additionally, a Procedural Upgrade Program was completed in 1993. While improving performance, as indicated by reduced numbers of events caused by personnel error, the licensee recognized that satisfactory performance was not yet achieved. Consequently, the licensee commissioned a special Comprehensive Assessment of Performance Team (CPAT) in the summer of 1993 to review and assess PSE&G's performance as indicated by the assessment of several deficient conditions and situations over the last few years. The CPAT activities are now completed and the results have been factored into the Nuclear Department Implementation Plan (Plan). The Plan identifies the program for implementing a comprehensive series of measures designed to effect and assure performance improvement. Actions were also taken prior to the event relative to leadership improvement, including organizational structure changes, reconstitution of the organization with more capable supervisors, and established requirements for increased supervisory oversight activities in the plant. An additional operating engineer has been assigned to provide in-field oversight and direct monitoring of the performance of supervisory personnel until all management enhancements are in place.

The management of Quality Assurance and Nuclear Safety Review Oversight Groups has recently been changed to improve oversight effectiveness. Other personnel supervisory changes have been accomplished to effect better overall performance. An independent consultant has provided an evaluation to assure the selection of properly qualified personnel for this area. Enhanced procedures and policies for safety reviews, audits, assessments, and communications of findings were established prior to the event.

Subsequent to the event and until the results of the CPAT effort are established and the planned enhancements in organization, personnel, and policy are completed, an Augmented Independent Oversight group has been selected to maintain full oversight coverage on all shifts, 7 days per week. The group has been directed to monitor activities such as reactor startups and shutdowns, low power operations, special tests and surveillances, major system and maintenance evolutions, work control performance and control room conduct, and shift turn-overs and planning meetings. The individuals will provide daily feedback to the Manager of Nuclear Safety Review, and weekly feedback to the Vice President and Chief Nuclear Officer. The Augmented Independent Oversight coverage will be maintained until significant improvement are noted in station performance and in the quality of the Nuclear Safety Review function.

Finally, the licensee has expressed confidence that these structural and personnel changes will provide the impetus and management attention necessary for significant and lasting improvement.

NRC Followup: Previously, the NRC has reviewed and assessed the licensee's CPAT effort. The CPAT was thorough and developed a comprehensive list of problems and weaknesses that appear to be causal to the recurrent failures noted in the licensee's performance. The NRC has also reviewed the Nuclear Department Tactical Plan which identifies the action and performance schedule to resolve each generic problem or weakness identified. The plan is very aggressive and thorough in the approach to resolution of the weaknesses. The schedule, while extending into 1995 for some of the more difficult matters to resolve, appears timely in view of the scope of the effort. NRC has already noted aggressive action to re-evaluate the quality and performance of managers and supervisors in the Salem organization. Several replacements have already occurred, including the replacement of the previous General Manager-Salem Operations with the current Vice President-Operations for PSE&G.

NRC has reviewed the credentials of the individuals assigned to the Augmented Independent Oversight group. Their background, experience, and ability seem to be appropriate for the task at hand. It is the expectation that the group will be successful in its endeavor to monitor the quality of performance and provide the necessary feedback to the right level of management to assure effectiveness and management cognizance of the quality of operations.

While a positive trend has not yet been demonstrated in Salem performance, the near-term and long-term actions initiated by the licensee appear to be sufficient to cause improvement if management maintains their commitment to the program.