From: Ivan Selin (IXS)
To: wmb, lep (William Beecher, OPA/Linda Portner, OCA)
Date: Wednesday, May 18, 1994 10:11 am
Subject: biden press conference

The announcement of Biden's press conference says that he asked us to hold up restart until all issues resolved, implying that we refused. [redacted]. The disageement is not one of policy -- we agree that issues should be resolved before restart -- but of technical judgment.

I would feel better if Salem were not having problems with the same valves which caused the shutdown in the first place.

CC: hlt, WTR, MSC

LAST BEFORE FINAL

Enclosure

Status of Major Issues Affecting Restart Activities at Salem-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 event. 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. Spurious high steam flow signals were previously identified by the licensee, but their 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. 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 during the last outage [Nov '93-Feb '94] and will be installed at Unit 2 during 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 and identifies when recalibration should be accomplished.

The 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 concerning steam flow instrument drift. The licensee provided detailed information on their monitoring program and associated calibration adjustments that have been 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 action appears acceptable.

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 also 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 input 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 the two trains of SSPS respond differently.

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 were 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 controllers were 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 performance.

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. Resident 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 during the event 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, it challenges 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's 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 demonstrated. The NRC has reviewed the licensee's procedures and training of operators for coping with grass intrusions. Evaluation of these procedures is discussed below. Plant design and the procedures that the licensee now has in place assure that the loss of circulating water to the main condenser will not challenge the safety of the nuclear plant.

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 event, 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 that 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 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 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, assessed 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 operator action 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.

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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, assessed 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.

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PSE&G Response: The turbine trip procedure now incorporates guidance for operator response to inadvertent or excessive primary coolant cooldown conditions when reactor power is below the P-9 setpoint. The procedure revision now includes specific direction to the operator to go to a new procedure attachment if at any time primary coolant temperature reaches 543 degrees F or less; the Technical Specification minimum temperature for criticality is 541 degrees F. The attachment provides direction to the operator to recover primary temperature, and if temperature can not be maintained above the minimum temperature for criticality, to manually trip the reactor.

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 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, operators 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, the operators encountered situations where the EOPs did

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.

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PSE&G Response: The procedure for power operation of the Salem units now includes specific directions for maintaining primary coolant temperature above the Technical Specification minimum temperature for critical operations while performing a plant power reduction. The body of the procedure directs the operator to a new procedure attachment if at any time during the power reduction primary coolant temperature reaches or goes below 543 degrees F; the allowed minimum temperature for critical operations is 541 degrees F. The attachment provides direction to the operator to recover primary temperature, and if temperature can not be maintained above the minimum temperature for criticality, to manually 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, 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 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 using 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 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:

- 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.
- Event Notification and Communication

PSE&G Response: The licensee responded to the above identified concerns by the issuance of a Salem Operations Department Information Directive (ID) and simulator training lesson plan. Specifically, (1) operators received guidance relative to management's expectations on the quality of communications as to clarity and directness, and the avoidance of vague or imprecise instructions or responses; (2) formal training and guidance were provided relative to the management and control of operating personnel resources to assure that conservative actions are taken to either stabilize plant conditions in a safe and controlled manner or manually trip the reactor or turbine. The ID included guidance on where to assign personnel when the rod control system is in "manual", and the acquisition of additional personnel for significant off-normal events; and (3) the Senior Nuclear Shift Supervisors role relative to plant events was clarified to maintain supervisory overview and not become engrossed or involved in assisting the crew with EOP implementation.

All operating crews received the simulator training on the lesson plan derived from the event, and all shifts were required to read

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and understand the directions provided in ID prior to resuming a watch.

Before entering mode 2, the licensee will establish interim guidance for all communicators and shift supervisors relative to providing fuller detail and explanation on significant events. Action to modify the emergency plan relative to procedures on event notification and communication will be initiated with all involved state and local agencies within the next seven days.

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.

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D. Unit 2 Consideration

Issue: Considering the procedure changes, training and hardware modifications identified from the event for implementation at Unit 1, the NRC questioned what short and long term corrective actions were planned or 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 on use of MS-10 valves to control main steam pressure 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 instrumentation configuration and 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.

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 condition upgrades at Salem, including design changes that directly improved control room operations. Additionally, a Procedural Upgrade Program was completed in 1993. Although improving performance was indicated by the reduced number of events caused by personnel error, the licensee recognized that satisfactory performance had not yet been 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 Tactical 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 establishing requirements for increased supervisory oversight activities in the plant. An additional operating engineer has been

assigned to provide direct monitoring of the performance of supervisory personnel until all management enhancements are completed.

The management of Quality Assurance and Nuclear Safety Review Oversight Groups has recently been changed to improve oversight effectiveness. Other 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 was 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 appears thorough in the approach to resolution of the weaknesses. The schedule, while extending into 1995 for some of the more difficult

matters 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.