From: Robert J. Summers (RJS)/RI
To: CLM1, JCS3, RWC, CWH, DJH, KDS1, JRW1, JTW1
Date: Friday, June 17, 1994 3:28 pm
Subject: Salem Enforcement Panel

Gene Kelly plans to hold an enforcement panel regarding potential violations discovered during the Salem AIT on Monday, 6/20 at 2:30 p.m. in the DRS conference room. Draft violations will be provided at the meeting; however, the issues include:

(1) a corrective actions concern - failure to take timely and effective corrective actions for problems identified with the atmospheric dump valve controls and the high steam flow protection instruments.

(2) a loss of command and control in the control room when the SRO assumed the duties of the RO during the down power transient, and left the position of observing the big picture and directing the activities of the ROs.

(3) a failure to implement work controls procedures when the senior shift supervisor bypassed the safety interlock for condenser waterbox vacuum in an attempt to start a circulating water pump; and when the supervisor(s) in charge of work at the circulating water structure failed to maintain a record of safety tagging operations in support of the maintenance to repair screens, etc.

(4) a failure to implement E-Plan procedures for communications that led to incomplete event description being provided to the NRC during initial notification.

While not addressed as a specific violation, the overriding concern is that licensee management failed to take appropriate measures to ensure that the facility operators (in the control room) had the necessary guidance, hardware, staffing and prioritization of work activities to respond to the daily transients resulting from the grass intrusions at the circulating water structure.

CC: ARB, RRK, EMK, WDL, CSM, BJM, ECW

TO: C. Marco, OGC
J. Stolz, NRR
R. Cooper, RI
C. Hehl, RI
~~J. Hagan~~ J. Holody, RI
K. Smith, RI
J. White, RI
J. Wiggins, RI

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General Activity and Licensee Response History

- 3/89: Licensee response to Outage Team Inspection indicated plans to take strong and effective action to resolve findings, including improved design change processes and improved personnel training.

- 1989/90: Due to poor material condition of plant noted by NRC, licensee initiates Revitalization efforts to address procedures, material condition, corrective and preventive actions, and personnel performance. (Includes SW pipe replacement and procedure upgrade program).

- 1991/1992: Licensee discovered that several contractor firewatches had falsified documentation relative to firewatch activities. Subsequently, several personnel were terminated. Licensee performed comprehensive investigation. General enforcement action taken consistent with other NRC sanctions for other operator rounds falsification issues determined at several other facilities.

XXXXXXX - Refueling Outage
11/9/91- 4/19/92: Unit 2 .
4/4/91 - 8/16/92: Unit 1 .

General Occurence and Event History

- 2/83: Salem ATWS event. (Included due to significance)

- 10/88: Outage Team Inspection identified multiple examples of inadequate management oversight and control relative to design change, modification, and installation activities; and lack of attention to detail relative to 50.59 evaluations. QA audits noted deficiencies but management response was weak or ineffective. (Included due to similarity to current performance issues)

1988

- 6/89: SALP 88-99 (1/88 - 4/89) OPS 3, RADCON 2, M/S 2, EP 2, SEC 1, E/TS 2 imp, SA/QV 2

1989

- 4/90 - 5/90: Maintenance Team Inspection and Integrated Performance Assessment Team identify longstanding weaknesses in management oversight and control, insufficient supervisory presence in-field, ineffective corrective action implementation, inadequate maintenance processes and control, insufficient oversight of contractors, inadequate root cause analysis and determination for some events, and weakness in procedural adherence.

1990

- 9/20/90: SALP 89-99 (5/89 - 7/90) OPS 2, RADCON 2, M/S 2 dec, EP 1, SEC 1, E/TS 2, SA/QV 2

1991

- 11/9/91: Salem Unit 2 Turbine overspeed event caused by insufficient preventive maintenance and surveillance, failure to follow procedures, and inadequate root cause analysis (AIT, Severity Level III, no CP).

1992

- 4/92: SALP 90-99 (8/90 - 12/91) OPS 2, RADCON 2 imp, M/S 2, EP 1, SEC 1, E/TS 2, SA/QV 2

- 6/18/92: Salem Unit 2 shutdown due to feedwater pipe wall thinning caused by erosion /corrosion.

- 12/3/92: Harassment and intimidation of two SRG members by senior Salem managers occurred as reported by subsequent licensee investigation. OI investigation activities were initiated.

- 12/13/92: Salem Unit 2 loss of overhead annunciator event caused by operator failure to follow procedures for Remote Configuration Workstation; and LTA design specifications for OHA alarm and warning features. (AIT)

1983-1992

SALEM

General Activity and Licensee Response History		General Occurence and Event History
	March	
	X X X X X X X X X X X X X X X X X	XXXXXXXXX **3/16/93 - 6/30/93 : Unit 2 refueling outage**
• 5/93: NRC met with licensee and discussed recurrent programmatic deficiencies that contributed to the previous AITs, and the licensee inability to understand and resolve cause of deficient conduct and performance.		• 5/24/93 - 6/4/93: Several aborted Salem Unit 2 startup attempts due to rod control problems. Inadequate root cause analysis was a principal contributor. Poor problem resolution technique and ability was demonstrated. (AIT)
	June	• 9/93: SALP 91-99 (12/91 - 6/93) OPS 2, RADCON 1, M/S 2, EP 1 dec, SEC 1, E/TS 2, SA/QV 2
• 7/93: PSE&G initiates Comprehensive Performance Assessment to assess Artificial Island events, incidents, and occurrences for previously undiscovered, underestimated, or overlooked root causes.		• 10/12/93: Salem Unit 2 shutdown due to cracked EDG cylinder liners.
		• 10/93 - 11/93: $50,000 CP & Severity Level III violation f numerous examples of inadequate procedure adherence with personnel safety implications (live 125VDC cable cutting incident, several incidents involving failure to adhere to tagging procedures, , etc).
		• 10/1/93 - 1/24/94: Salem Unit 1 refueling outage (1R11), extended due to EDG cylinder liner problems (crack liners attributed to procurement deficiencies); Aux Feedwater pump problems (attributed to replaced parts that were of a different design than required); and, Main Feedwater pump problems (attributed to design changes implemented to support later digital feedwater modifications, i.e., the licensee did not fully understand the cause of oscillations, consequently the MFP was restored to original configuration.
	1993	

SALEM

General Activity and Licensee Response History

- 1/94: PSE&G concludes comprehensive assessment, concludes there are significant deficiencies in root cause determination, and the performance of offsite and line QA organizations. Subsequently, a complex Strategic Improvement Plan is established that identifies corrective measures and schedule for completion.

- 2/94: After being at power for 3 days, unit 1 tripped.

  2/94: Cal Vondra, General Manager-Salem Operations reassigned to non-nuclear posistion in PSE&G. Joe Hagan, Vice President-Nuclear Operations assigned as General Manager until permanent replacement is appointed.

  2/94: Salem reorganization initiated, including plant unitization, and establishment of new department managers for System Engineering/ Tech Support, Maintenance, and Outage Planning.

  2/4/94: Salem management took both units off line to dredge grass and mud in front of the Salem circulating water intake structure.

  2/24/94: Management Meeting to discuss CPAT findings and licensee plans and schedules for program improvement.

- 6/24/94: Salem Unit 1 rapid shutdown from 75% power due to condensate suction header overpressurization and water hammer.

General Occurence and Event History

- 1/27/94 - 2/13/94: Salem Unit 1 was subject to 2 reactor trips (1/27/94-trip from 10% due to feed reg valve problems attributable to previously ineffective troubleshooting efforts; 2/10/94-trip from 100% due to coincident loss of both 15 VDC control power supplies to EHC system due to unexpected actuation of over-voltage protection (crowbar), suspected to be caused by maintenance activities. On 2/11/94-licensee discovered that the mode switches to both air compressors for 1B EDG were in the off position due to work control problems; and on 2/13/94, while the unit was in Mode 2, an I&C technician error involving a pressure transducer associated with the atmospheric steam dump system caused the steam dumps to actuate. Consequently, excessive cooldown occurred and power increase from 2% to 5.6%, causing an unplanned mode change.

- 4/7/94: Salem Unit 1 trip from 25% due to operator error (Operators reduced power to 10% to compensate for grass intrusion, which enabled the 25 low power trip setpoint. To restore lower than normal Tave, operators withdrew some control rods which increased power in excess of 25%, which resulted in trip. Trip was complicated when two MSIVs and two FW isolation valve failed to close; and two turbine driven feed pumps failed to trip. SI actuated, PRT rupture disk blew-out, and the licensee declared a UE followed by an ALERT. AIT dispatched. Consequently, escalated enforcement action was taken (4 Severity Level IIIs with a $500,000 CP). General cause involve ineffective corrective action for pre-existing equipment deficiencies that provided challenges to operators (MS10), inadequate operator command and control, and ineffective management communication of expectations to the staff, and poor operator performance issues. (AIT)

  Precursors to this event (grass affecting plant operation) occurred twice in 1993, and once in 2/94. Subsequent problems with grass occurred in 6/94 and 12/94.

- 6/14/94: Salem Unit 2 rapidly reduced power from 100% to 70% due to grass intrusion.

Jan.- June 1994

General Activity and Licensee Response History

- 7/94: NRC Commissioners receive PSE&G presentation on April 7, event. Chairman informs PSE&G that Salem performance (4 AITs in 4 years) was unacceptable.

  7/11/94 - 8/25/94: NRC conducted a special Performance Assessment of Salem. Generally the assessment team found that there was no aggressive quality oversight of activities, and no proactive effort existed to correct existing system and equipment deficiencies that had the potential to challenge operators and system performance. Weakness were also found in maintenance programs relative to procedure adherence, post-maintenance testing, and control of work activities. In operations, a significant number of "work-around" issues were identified that operators had accomodated and accepted as normal. Though engineering activities were generally assessed positively, weaknesses were noted in engineering oversight of vendor-designed modifications. Plant support activities were acceptable.

  7/30/94: PSE&G executive management, as part of an overall performance improvement effort (which involved assessing the performance of all personnel assigned to support Salem), terminated or otherwise forced the resignation of about 55 personnel that were deemed to be low-level performers in the Salem orgainization. The terminations mainly affected supervisors and technical personnel in non- bargaining positions, and included L. Reiter, General Manager-Quality Assurance and Nuclear Safety Review and other managers in that organization.

- 8/94: EDO informs Miltenberger, LaBruna, and Hagan that he will not be able to defend continued Salem operation in the event of another AIT.

- 10/94 Steve Miltenberger, Vice President and Chief Nuclear Officer was replaced by Leon Eliason. Subsequently, Eliason presides over the reorganization of PSE&G's nuclear division into a subsidiary reorganization of Nuclear Division, Nuclear Business unit. Eliason is named President of NBU.

General Occurence and Event History

- 10/13/94 - 2/16/95: Salem Unit 2 refueling outage (2R8). Projected 77 day refueling outage delayed due to leaking pressurizer code safety valves and single failure susceptibility of the Solid State Protection System.

  10/29/94-11/4/94: several ineffectively controlled non-safety related maintenance activities, including near miss cutting 4160V cable.

July-Oct.
1994

SALEM VIOLATIONS
APRIL 1, 1992 TO JULY 12, 1994

ENCLOSURE 8

REPORT	ISSUED	SEVERITY	AREA	DESCRIPTION
92-07	7/2/92	IV	SA/QV	Control room habitability, storage of ammonium hydroxide not communicated to NRC for evaluation.
92-11	7/30/92	IV	M/S	Failure to follow procedures regarding control of measurement and test equipment.
92-16	12/16/92	IV	E/TS	Inadequate corrective actions by engineering for identified deficiency regarding fire damper.
93-08	5/5/93	IV	SA/QV	Weaknesses identified in the licensee's implementation of the 10 CFR 50.59 program.
93-11	5/7/93	IV	SEC	FFD supervisory training issues.
93-15	7/12/93	IV	OPS	Availability of steam driven AFW during entry into Mode 3.
93-21	11/3/93	IV	OPS	Failure to initiate a timely shutdown of Unit 1 following failed surveillance test. (Licensee identified)
93-23	1/10/94	IV	M/S	Diesel generator air start system operability.
93-23 (Violation resulted from Enforcement Action - Civil Penalty)	3/9/94	III	M/S	Failure to follow maintenance procedures.
93-82	11/30/93	IV	OPS/E/TS	Failure to follow station procedure for measuring battery cell voltages.
93-27	2/10/94	IV	M/S/OPS	Inadequate control of troubleshooting and corrective actions regarding RHR check valve leakage.
94-06	4/26/94	IV	OPS	Failure to comply with TSAS regarding PORVs.
94-07	6/29/94	IV	E/TS	No written safety evaluation for replacement 460V vital bus transformer.
94-16	6/30/94	IV	P/S	Access Control of Vehicles.

SALEM SIGNIFICANT EVENTS SUMMARY
(9/95 - PRESENT)

- September 1, 1995: An Unusual Event (UE) was declared due to the transport of a potentially contaminated individual offsite to a medical facility. The individual was subsequently surveyed and found to be uncontaminated. The licensee terminated the UE. Licensee actions were appropriate.

- September 26, 1995: During steam generator inspections during the current refueling outage, the licensee identified a number of tubes that exceeded the plugging limit. During a review of the 1993 inspection results, many of these same tubes were found to exceed the plugging limit in 1993, but were not plugged. NRC followup concluded that contractor oversight was weak.

- October 5, 1995: The licensee declared an alert due to a loss of all overhead annunciators for greater than 15 minutes. In this case, the licensee was slow to classify the event; emergency response to the event was untimely and incomplete; and the state of New Jersey was given the same information repeatedly on hourly status calls. A special inspection was dispatched.

- October 12, 1995: The licensee discovered that two service water (SW) pumps could potentially cavitate/runout during the recirculation phase of a LOCA. The problem resulted from certain postulated single failure scenarios where the system did not align as expected in the design basis. The licensee developed procedure changes and proposed design changes to be implemented prior to startup.

- November 16, 1995: The licensee discovered that a damper designed to go full open in response to a high energy line break in a turbine driven auxiliary feedwater pump (TDAFWP) room, would not open fully. The damper needs to open fully to preserve the integrity of the enclosure. The licensee agreed to resolve this issue prior to plant startup. This deficiency affects both units.

- November 21, 1995: The licensee completed an engineering evaluation of the intermediate head ECCS throttling valves at both units. The findings of the evaluation were that the valves were closed too far, such that the valve seats could erode excessively. The seat erosion could cause flow to increase to the point where pump run-out might occur, leading to pump damage. Both cold leg injection and hot leg recirculation valves are susceptible to this problem. The licensee is evaluating corrective actions and will not restart until this problem is resolved.

- November 29, 1995: The licensee declared all emergency diesel generators (EDGs) inoperable due to excessive phase amplitude imbalance. This occurred due to a unique electrical alignment while shutdown.

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- January 3, 1996: The licensee discovered that numerous safety related motors may have thermal overloads that were set improperly. The overloads in use were not required to conform to the industry standard technical margin of 10%. As such, spurious equipment trips could be expected in accident conditions. The licensee has declared the affected equipment inoperable and will make the repairs prior to plant restart.

- January 10, 1996: A licensee investigation in response to NRC Generic Letter 95-07 discovered several motor operated valves which would not be capable of fulfilling their safety related function of moving to the open position due to pressure locking or thermal binding. The containment spray pump discharge valves, centrifugal charging pump discharge valves, the residual heat removal pump cross tie valves to the suction side of the intermediate pumps and high head pumps, are all affected. These valves are normally closed and are required to open during accident conditions. A tracking Technical Specification (TS) action statements were entered and licensee evaluation is continuing. These problems will be corrected before startup.

- January 24, 1996: The licensee declared an Unusual Event due to an onsite fire lasting longer than 10 minutes. Technicians ignited a protective coating in a service water (SW) pipe while performing preplanned demolition work. The fire brigade responded and extinguished the fire within 13 minutes. The NRC concluded that previous corrective actions from similar fires were inadequate.

- March 18, 1996: During a self assessment of their special nuclear material program, the licensee discovered that eleven incore flux detectors (4 mg of U-235) were not properly accounted for. The licensee believes they were erroneously shipped to Barnwell, SC in 1981 based on current interviews with radwaste personnel. However, this cannot be proven. The shipping records are still being investigated.

Faxed to
Bill Lazarus
1/11/96

SALEM

Due to frequent operational transients, initiated or complicated by equipment failures, procedural adherence problems, poor root cause determinations, and less than adequate management oversight and involvement, Salem has been discussed during five SMMs since January 1990, most recently in June 1995. The NRC has performed four AIT inspections in the period 1991-94, and has closely inspected numerous automatic trips or forced shutdowns during the same period. Following the January 1995 SMM, it was determined that a visit by NRC senior managers to the Board of Directors was an appropriate means of communicating the NRC's growing concern over Salem's continued poor performance. This meeting took place on March 21, 1995.

As a result of continued performance deficiencies, poor material condition, weak management oversight and ineffective corrective actions, coupled with the Technical Specification required shutdowns of both units, Region I issued a confirmatory action letter (CAL) on June 9, 1995. This CAL delineated licensee commitments that must be satisfied prior to the restart of either Salem unit. Additionally, in October 1995, a $600,000 civil penalty was levied on Salem as a result of six Severity Level III violations, five of which were associated with the licensee's failure to promptly respond to and correct conditions adverse to quality over an extended period of time.

Over the last six months, Salem has put in place a new management team and preliminary indications are that it has developed a comprehensive action plan to improve the safety focus and overall performance of the Salem organization. Both units are currently in outages, with a substantial amount of work being performed to significantly upgrade the plant material condition. Unit 1 is currently scheduled for restart in ~~April 1996~~ June 1996 and Unit 2 is slated for ~~startup~~ core reload in ~~July 1996.~~ September 1996

Besides upgrading the plant material condition, a number of programmatic concerns are being addressed during this extended outage. Among the more meaningful areas for improvement being pursued by Salem management are the quality and timeliness of root cause determinations, operational procedure upgrades, standards of acceptable operator performance, operability

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determinations, tagging control, control of work activities, and system engineering performance. Substantial management oversight, including both on and off site review committees, has resulted in a clear message that performance standards must be elevated for the plants to operate successfully. It remains to be seen how effectively station personnel will translate these expectations into measurable performance improvement.

ORGANIZATIONAL EFFECTIVENESS ASSESSMENT

CHARTER:

Perform a management-level assessment to determine:

1. *Why corrective actions previously defined to correct performance weaknesses and deficiencies have not been effective in achieving sustained performance improvements, and,*

2. *Identify organizational and personnel weaknesses that will hinder current performance improvement efforts.*

This self assessment will evaluate the Salem organization's ability to effect a prompt improvement in operational performance, followed by continued long term improvement, such that NBU goals to reach top quartile performance can be realized. Substantial effort has been previously expended to identify performance weaknesses and implement corrective actions. Many of these problem areas will be reviewed during the course of this assessment to evaluate corrective action effectiveness and gain a better understanding as to why sustained performance improvement is not being achieved.

The conduct of the assessment will include observation of activities and interviews with personnel that represent a cross section of responsibilities and levels. A briefing of PSE&G management will be held to convey findings and recommendations. Updates will also be provided to NRC management. A final report of the Team's findings and conclusions will complete this assessment.

Jeffrey A. Benjamin

Jeffrey A. Benjamin, Director - QA/NSR

Leon R. Eliason, Chief Nuclear Officer

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BACKGROUND

A self assessment of the NBU's organizational effectiveness was initiated by the CNO because the current improvement actions at Salem were not yielding the expected results. The actions resulting from previous assessments were aimed at achieving a high level of operational safety and reliability at Salem. Since problems have persisted, the question arises as to whether current actions are adequate, and if they are, why haven't we achieved the desired improvements in plant performance and what else should be done to achieve performance goals? The assessment is focusing on organizational effectiveness and personnel performance.

TEAM COMPOSITION

This assessment will be performed by a team of highly-qualified, independent persons with demonstrated skills in managing quality operations and performing critical assessments. The team will report the results to the CNO. The following is a listing of team members, their affiliations and associated areas of responsibility:

Ken Harris (formerly FP&L): Operations (Team Leader)
Jay Doering (PECO): Corrective Actions
Carl Andognini (formerly APS): Maintenance/Surveillance
Gerard Goering (NSP): Engineering/Technical Support
Bill McLane (PG&E): Outage Performance

FUNCTIONAL AREAS AND PRINCIPAL ISSUES FOR ASSESSMENT:

- Operations
  - Operations "ownership" of the plant
  - Effectiveness of interfaces and communications
  - Effectiveness of operation's control of activities in progress

- Maintenance
  - Control of maintenance activities, including planning
  - Conduct and scheduling of maintenance
  - Support of maintenance activities

- Engineering/Technical Support
  - Effectiveness of system engineers in support of operations
  - Adequacy of engineering prioritization to support plant needs
  - Effective use of design engineering in support of plant operations
  - Effectiveness of communications and interfaces between engineering, operations and maintenance

- Oversight
  - Management's balance of production vs. safety
  - Management control/oversight plant activities

- Corrective Action
  - Management involvement/ownership of correction action program
  - Effectiveness of root cause determinations and follow through to problem resolution, including operations/engineering involvement

- Outage Performance
  - Milestone planning and scope control
  - Communications
  - Outage management controls
  - Outage planning/scheduling controls

The following are typical questions which may be asked during interviews with NBU personnel:

- How effective is the organization in dealing with known problems by finding root and contributing causes and instituting effective and lasting corrective action?

- Have clear expectations and standards been communicated from the next higher management/supervisor level?

- How do standards/expectations and planned actions at Salem correspond to those current in the industry? How effectively are they conveyed, accepted and implemented?

- Have managers/supervisors accepted these standards/expectations and have they rolled them down into the organization such that they are accepted?

- Do support groups place adequate priority on operations and are interdepartmental communications effective to resolve emergent work?

- Have managers/supervisors adequately self-assessed their own performance and identified needed improvement?

- Have managers/supervisors defined and planned their work in accordance with prioritized work activities consistent with available resources? Have managers/supervisors identified appropriate results and performance indicators?

- Have managers/supervisors reached agreement on their plans and priorities with the next level of management? Are managers and supervisors held accountable for performance relative to plans?

- Have managers/supervisors identified needs for additional resources and taken action to acquire more; and has management supported this action?

- What is the overall assessment of the situation and trends in each functional area and across organizational interfaces?

- What short/long term actions are appropriate to put Salem on a well-defined path to top quartile performance?

OPERATIONS AND MAINTENANCE

OVERVIEW

The integrated assessment of the Operations and Maintenance Departments consisted of a review of departmental documents including procedures and records; interviews with personnel at all levels (operations, craft technicians, first line supervisors, and managers) and interface relationships with other department personnel. For the Operations Department, observations of control room activities including shift turnovers were conducted.

OBSERVATIONS

- A great deal of confusion exists within the Nuclear Business Unit as to whether the Operations Department has the operational ownership of the plant. The operators perceive that the plant is schedule driven and supporting organizations feel schedules are not adhered to and are revised to meet operators needs and/or desires. The operators feel that if they had ownership of plant, items such as the work around list, shift supervisor administrative burdens, lack of staff to complete shift complement, insufficient interdepartmental support from the Planning, System Engineering, and Nuclear Engineering departments and the perceived lack of support from upper management, would be resolved.

- The organization clearly lacks a "team approach" in the resolution of problems. Some examples are as follows:

    1. In the determination of a "Root Cause" for an event, a team approach is not utilized. Individual departments such as Operations and Maintenance are adamant that the use of other departments such as System Engineering and Nuclear Engineering are generally not needed, and if they are, it will be on a request basis.

    2. Operability determinations are completed without System Engineering and Nuclear Engineering involvement unless specifically requested.

    3. Design change packages do not always receive operability and maintainability review prior to finalization.

- From both the Operations and Maintenance departments' perspective, the 60 day time limit for the upcoming refueling outage on Unit I, which negates the ability to install the new digital feedwater control system in conjunction

with the commitment to install Reg. Guide 1.97 is incomprehensible (could be interpreted as sending an inappropriate message relative to providing resolution to long standing operational problems). Little, if any, upper management communications has been received by the organization on the matter and the teams assembled to conduct feasibility studies for the installation have been disbanded. However, conversations with senior management have revealed that the installation of the digital feedwater system during the upcoming refueling outage is still under consideration.

- The Maintenance organization, especially in the mechanical discipline, does not have a prepared work package backlog; therefore, there are periods during which qualified personnel are either idle or involved in tasks that are of a low priority or that are below their level of qualification. Either the processes utilized and/or the staffing levels of the Planning and Scheduling Departmen[illegible] adequate. In addition, it is estimated a large percentage (in the 3[illegible] the work packages received by the maintenance departme[illegible] corrected in the field by the maintenance personnel or returned to Plann[illegible]g and Scheduling Department.

- In both the Operations and Maintenance Departments, work is either delayed, rescheduled or postponed because of "spare parts." A review to determine whether the spare part was not in the warehouse, the work package involved insufficient or inaccurate parts lists or the ordered parts were not received prior to scheduling of the task was not completed. The perception of both departments is that management is not supportive in having adequate parts available.

- The Operations Department work control center located outside the unit control rooms does not function as a work control center and as such cannot meet the needs of the plant. Currently, it's primary function is to perform tagging to support maintenance; but, even for this function, staffing levels are inadequate.

- In the Maintenance Department the craft personnel, in the Operations Department the reactor operators, and in both departments the first line supervisors, appear to be competent, capable, and hardworking individuals who not only want, but need leadership. In addition, personnel in both departments state that:

  1. Managers are unavailable to provide leadership because of the amount of time spent in meetings and resolution of ATS items, etc.

  2. Managers are unwilling to make decisions for fear of repercussion and delegate even minor decisions to the higher management level.

3. Management continually fails to obtain input from the individuals involved in a specific activity prior to making a decision. As an example, first line supervisors stated that no communication between them and management took place prior to the issuance of the work standards for first line supervisors in the Work Standards Handbook.

- In the Operations Department, most reactor operators are unwilling to accept supervisory positions because:

  1. They perceive that the shift supervisors are the "managerial bag-man."

  2. The position is a glorified clerk.

  3. Financial incentives for the position do not exist.

  4. The shift supervisors are hindered from performing the function of the position because department management establishes the priorities for the position.

  5. The shift supervisor position is at times perceived as a work control supervisor and not a shift supervisor.

- Observations indicate that events or even near events are occurring that could be significantly reduced or eliminate if appropriate senior management guidance and expectations were clearly delineated to all plant personnel.

- Personnel in the Maintenance Department are concerned that unitization will not appropriately address the areas of specialization.

RECOMMENDATIONS

- Senior management should take immediate appropriate actions to insure that all personnel clearly understand that operational ownership of the plant has been managerially delegated to the Operations Department.

- Interdepartmental barriers that currently prevent Nuclear Business Unit departments from acting as an "Integrated Team" must be eliminated and managerial guidance provided, with appropriate accountability, to ensure that implementation has occurred and interdepartmental relationships continue to improve.

- Management guidance and expectations relative to a 60 day Unit I outage and the feasibility of installing the digital feedwater control system must be communicated to all plant personnel.

- Management must determine the causes why adequate numbers of quality prepared work packages are not available for the Maintenance Department, and must take appropriate corrective action.

- The cause for work being delayed, rescheduled, or postponed because of spare parts must be identified and corrected.

- An in depth review of the staffing requirements for the Operations Department to support shift complements, support interdepartmental needs such as tagging, reduce administrative burdens on key personnel such as the shift supervisor and reduce overtime is required to be completed and implemented immediately.

- A comprehensive assessment must be conducted and appropriate actions implemented to provide the reactor operators the necessary incentive to become shift supervisors.

- To reduce events, senior management must immediately provide guidance and expectations to all personnel relative to the fact that extra caution shall be exercised prior to the conduct of daily activities. The scheduler pressure must be eliminated and individuals must be encouraged to STOP prior to execution of any activity if doubt exists.

ENGINEERING/TECHNICAL SUPPORT

OVERVIEW

This assessment consisted of a review of many current internally and externally generated assessment documents. Interviews were also conducted with personnel from Salem, Hope Creek, Engineering, and site management.

OBSERVATIONS

- Lack of leadership and management direction has resulted in the Salem Technical Support functions for day to day operations being misdirected and poorly focused. It is clear from interviews that the Salem organization retains a PSE&G fossil based focus. This attitude of "we can fix anything once it breaks" results in general fire-fighting that, while giving the organization a good feeling when fires are well fought, does not form a solid foundation for a well operated nuclear station. The Technical Support/Engineering sections are viewed as a resource only to be called upon when needed. The idea that the technical sections should be intrusive and lead responses to problems in the day to day operation of the plant is not prevalent with Salem personnel. This results in a lack of proper focus for the technical support functions coupled with a general lack of leadership and direction.

- From interviews and observation it is clear that the Hope Creek Technical Support organization has a well functioning system engineering program. From a historical perspective, the basic difference between the Salem technical support approach and the Hope Creek approach has been apparent to site management since the start-up of Hope Creek and the initiation of the system engineering program at Salem. When questioned about this difference, management recognizes the strengths of the Hope Creek situation and the problems associated with the Salem organization. When this line of questioning was pursued further as to what has or is being done to address this difference, the response was unsatisfactory. There is no evidence of an investigation of this difference or an action plan to upgrade the Salem system engineering even though this is one of the areas that has received significant criticism by INPO and the NRC. This recognized situation has been allowed to exist for years with no effective action being taken by the management team.

- There exists a lack of proactive, aggressive interfacing by the system engineers with the Operations and Maintenance Department in support of

day to day operations. There is currently a general approach that both the system engineers and the design engineers will get involved with issues "when called." This on call approach is directly opposite to the intrusive system ownership that is expected in a well functioning system engineering program. There should be no need for the site General Manager to ask who owns an emerging problem at the Plan of the Day meeting. The system engineer should be reporting on the problem and the needed actions for addressing it at that meeting.

- There is a lack of an integrated process for the prioritization by the operating department in the following areas:

  1. Technical issues

  2. Plant modifications

  3. Corrective maintenance

  The lack of prioritization results in the mindset that everything is of equal importance and the organization and the individuals feel overwhelmed. It is a random chance that the individual system engineers and the engineering section personnel are working on the most value added items to support current operational needs.

- The Technical Support Department and specifically, the system engineers have become integrated into many relatively low value added processes. Management must protect the system engineers available time carefully to ensure they have sufficient plant time to allow them to be effective in real time support of current issues.

- In an attempt to respond to the feeling of being overwhelmed, the Technical Support Department has formed a special group of system engineers that are to be "first responders" to requests for technical support. This demonstrates management's lack of understanding as to what system engineering is to accomplish. This group, while well intentioned, will only inhibit the system ownership by the assigned system engineer. The stated intent of this group is to insulate the assigned system engineers from the day to day request of the operating and maintenance organization and allow them to attend to their real system engineering work. This is directly counter to what is needed in the Technical Support Department at Salem.

- There is agreement that the technical resources available to the Salem operating organization by the technical support group and the site design engineering organization are very good. The problem occurs in the focusing

of these resources to solve the most operationally important technical issues in a timely manner. When a serious reoccurring issue becomes visible, the focus of these technical resources occurs, and a final solution is developed. The integration of these technical resources to support the system engineers' work has not occurred such that this support occurs in a seamless and timely manner. Expectations have not been communicated to the two engineering organizations that design support for operational issues need a high priority and that technical support is to engage the design group immediately when uncertainty exists but will retain ownership of the issue.

- A program to bring the Hope Creek and Salem Technical groups together for sharing of best practices, resources, team building or personnel rotation is in place but is not effective.

- There is no evidence that the Salem station management team meets on a regular basis to address strategic technical issues or to prioritize resources or management issues.

- The digital feedwater modification which will address many of the Hagan control problems that plague the plant is being delayed due to outage schedule constraints. This modification has high priority based on operational need. The site maintenance team to date has not developed a plan to address the schedule constraints and the need to install the modification within the schedule constraints.

- There is multiple indications of senior management micro-managing technical issues which results in the plant technical group not owning the issues and not being allowed to resolve the issues using normal processes. The result is confusion as to who has responsibility for an issue and the plant technical support group being ineffective in dealing with problems.

- Both the system engineering and maintenance technical support controls functions are overwhelmed and have been identified by Operations as a weak support area. The issues appear to have been caused by historical inattention to preventive maintenance and poor quality of older modifications. There is no indication that management has recognized this critical overloading nor is management taking any actions to address it other than allowing unlimited overtime for the personnel.

- Once a plant modification is approved for implementation, the system engineers have little influence on the scope of the solution that is the final design. This approach can and has resulted in design solutions that are not responsive to the problem and tend to be complete change out of systems

with the latest technology rather than an engineered upgrade to the existing equipment.

- There is limited indications that the technical group interfaces with other nuclear plants to discuss approaches to problems. This appears to be a historical situation and is currently not being addressed in an integrated manner. When discussed with Salem personnel, the general response is that people are too busy to talk to any outside organizations.

- There is evidence that management's over zealous enforcement of goals for the technical group to meet reductions in backlog numbers has resulted in sending the wrong message to the organizations as to what is important. Attention to meeting goals is impacting the technical section's ability to focus on support of day to day operational problems.

RECOMMENDATIONS

- Conduct a feasibility study to determine whether all site engineering functions should be reorganized to report under the Vice President of Engineering.

- To allow this organization to succeed, a critical examination of the current site management team needs to be performed to upgrade its capabilities to provide the leadership and management skills to address the current shortcomings at the Salem station. There are numerous examples in the nuclear industry where the proper application of strong leadership and management skills have made dramatic improvements to plants with significant problems. The application of these skills in a timely manner at the Salem station will address the negative observations discussed in the above finding and will allow the organization to succeed.

- The existing opening of Manager of Technical Support, which is to be filled by an outside individual, requires an individual that has experience with an aggressive and well recognized nuclear system engineering program.

- Additional external experienced individuals should be placed in the organization to ensure that full time facilitation of the necessary changes will not be diverted by external events that could impact the line individuals' attention to the change process.

- Relocate the small projects group inside the security fence to enhance the communications between this group and the plant organizations. This is presently an effective group and by moving the group to a closer physical

proximity to the plant organization, the plants operational needs could be more effectively addressed. Having a dynamic, quick response group that can address operational work around issues in a timely manner is a critical need for the Salem operators. This group would team with the system engineers who should scope the solutions and sponsor the projects.

- A cross functional team should be given the task to revise the scope and installation plan for the digital feedwater system at the next outage. Input from other sites can be used to ensure that the major benefit from the project can be realized and the installation would not extend the outage beyond the current budgeted schedule.

- Rank in terms of value added the various programs and processes that the system engineers are mandated to be involved in. Based on this importance ranking, reduce the routine load on the system engineers significantly. This will allow the necessary time for the engineers to develop the involvement and ownership of the daily and reoccurring operational problems of their respective systems.

- Institute a process to be applied to the current backlog of technical issues to ensure that the most operationally significant are being appropriately prioritized.

SALEM OVERSIGHT

OVERVIEW

Oversight at Salem consists primarily of audits and surveillances performed by the "corporate" and the plant QA organizations respectively. In addition, the Nuclear Safety Review (NSR) organization conducts studies and issues reports which may be accompanied by recommendations. SORC is supposed to provide oversight of plant operations for the purpose of detecting nuclear safety issues, although it does not appear that this is being done on a systematic basis.

The QA function was analyzed by reading audit and surveillance reports, interviewing QA employees, and attending SORC meetings.

OBSERVATIONS

- The ability of the QA organization to support needed improvement within the line organization was limited due to low performance. Weaknesses include;

  1. Audit report quality was inconsistent. Though occasionally good, overall they tended to be poor.

  2. Interviews with QA and line personnel indicated that QA has lacked credibility in the past due to instances of poor performance.

  3. QA has not made a routine practice of assessing themselves by comparing their findings against those of external oversight.

  4. There did not appear to be a consistent policy of bringing only high performing employees into QA.

- QA personnel did not consistently use findings as an important tool to leverage organizational improvement. Over the past five years, the number of findings decreased even as the plant performance was decreasing. Other indications of this are;

  1. A review of audit reports reveals that findings are often not issued even when significant performance deficiencies are noted.

  2. A well executed audit of Corrective Action Programs was performed in the third quarter of 1994 resulting in a finding being issued to the Senior Vice President/Chief Nuclear Officer. The agreed upon

corrective actions appeared potentially effective, but due partly to lack of QA follow through on the finding responses, they were ineffective.

3. Historically, extensions to due dates were easily obtained and frequently abused.

4. When QA management decided to move to a greater emphasis on performance based auditing, they were unable to articulate what that meant resulting in frustration for audit personnel when findings were rejected by their management. Unclear expectations on what constituted a performance based findings tended to inhibit the writing of additional findings.

5. Another negative incentive for issuing findings was the additional work load created for the issuer of the finding who would take on the added responsibility for follow up of corrective actions while still maintaining responsibility for scheduled audits.

6. Surveillance personnel had difficulty in issuing findings due to inability to maintain independence while in close association with the line organization. This may be evidenced by a relatively low number of findings issued relative to the Audit group despite the Surveillance group's proximity to the line organization on a daily basis.

- Inappropriate behaviors within the line organization reduced the impact of QA. For instance;

1. In the past, some (estimated about 30%) line managers would strongly resist the issuance of QA findings. While this was highly dependent on the individual manager, it indicates deficient leadership in proper management behaviors and appreciation of the role of QA.

2. An event occurring in Dec 1992 is frequently discussed indicating that it remains an issue with some QA employees.

3. One site organization indicated that their management recorded QA findings in their performance evaluations.

4. The line organization expected that the Surveillance Group was "part of the team" implying that they should participate in activities that were in fact line responsibilities. This was also a problem for NSR personnel.

5. Monitoring of the effectiveness of corrective actions resulting from QA findings is not routinely done by the line organization. (neither did QA raise this as an issue.)

- Recent changes in executive and QA leadership have produced significant improvement initiatives within the QA organization.

1. A new Director of QA was named who has the high standards, the understanding the QA function, and the leadership necessary to use the QA organization to leverage organizational improvement. He is able to clearly articulate the important areas requiring improvement within the site organizations.

2. Substantial changes are being made to the leadership within the QA organization. A systematic approach is being taken to assure that high performers will fill QA supervisory/management positions.

3. Sound strategies on implementation of the audit program are being developed which will produce the greatest organizational impact. This includes a shift to a more performance based use of QA resources, and plan for scheduling activities which optimize the benefit of the audit program.

4. Innovative means of self assessing QA effectiveness have been designed and are beginning to be implemented.

5. A QA process called "Found and Fixed" will assist the organization in focusing resources on priority issues.

6. Use of the NRB as a QA assessment function, along with performance monitoring of the NRB itself, has begun under the chairmanship of that committee by the Director of QA.

<u>RECOMMENDATION</u>

- The revitalized QA organization being implemented, including the initiatives identified above, will clearly address the historical performance issues. This effort must remain highly sponsored and NRB should provide continual oversight until a high performance organization is achieved.

- Senior management historically has not provided the leadership to create a work environment where QA feed back was a valued learning tool. It must

be clearly communicated to the line organization that QA feed back is a valued input for continuous improvement and validation of self assessment.

- SORC should upgrade its "Review of facility operations to detect potential nuclear safety hazards" (Tech Spec 6.5.1.6h) to a more rigorous assessment process.

- The reconstituted NRB should receive strong sponsorship from the Senior Management team. NRB should monitor QA performance.

SALEM CORRECTIVE ACTION PROGRAM

OVERVIEW

The Corrective Action Program (CAP) at Salem was evaluated as follows;

1. Interviews were conducted with a representative cross section of the line and Quality Assurance (QA) organizations. A specific interview protocol was used for many of the interviews. Concerns were drawn from the interviews based on the experience of the interviewer.

2. Corrective action data was reviewed including incident reports, Action Tracking System (ATS), and implementing procedures to assess the proficiency of the Salem organization at learning from experience.

3. Meetings were attended where various elements of corrective action processes were implemented.

4. A historical review of the organization's response to external assessments was conducted.

While the programs which support the corrective action process were examined in detail, the overview took a broader look at organizational learning.

OBSERVATIONS

- There is ample indication that the organization continues to experience problems which could have been prevented if adequate root cause determinations had been made, and corrective actions taken, in response to previous events. For example;

    1. Repeat problems with Hagan controllers had not received sufficiently rigorous analysis and correction to prevent their contributing to a recent event which required another root cause analysis.

    2. A recent serious clearance error is symptomatic of failure to learn from a number of minor attention to detail tagging errors attested to by maintenance supervisors.

    3. Several plant modifications, including modifications associated with waste gas analyzers and Dixon indicators did not resolve the entire problem which they were intended to correct.

4. Repeat events were identified by analysis of Incident Report (IR) data over the last 15 months.

   - 94 IRs indicated inaccurate drawings
   - 64 configuration control problems were identified
   - Difficulties in control of maintenance activities were identified 36 times
   - Tagging problems appeared as causal factors in 32 IRs

- The present processes which support the CAP are not up to current industry practice, however, if implemented in accordance with the governing procedures, this would greatly enhance the CAP process.

- The existing CAP has not been utilized by the plant staff to improve performance. The following deficiencies were noted:

1. Reliability Services has developed a good data base of event data and have developed sound insights into where the organization needs to improve. For the most part the line organization is "to busy" to take advantage of their work.

2. Incident reports are not classified as to how rigorous an evaluation is to be performed. This has resulted in an excessive burden on the line organization resulting in a reduced appreciation for benefits of properly executing the program.

3. Causal factors used to formulate corrective actions are too shallow.

4. Corrective actions tend to address symptoms and not underlying causes.

5. There is inadequate follow through on corrective actions.

6. The data analysis which is being performed is marginally useful in the format presented and is not used by most line managers to improve organizational performance.

7. Generic considerations are weak.

8. The line organization does not verify the effectiveness of corrective actions.

9. Line managers do not review IRs at close out so are not aware of the quality of the investigations performed by their respective organizations.

10. Station Operations Review Committee (SORC) only reviews IRs if they become LERs.

- Management has not adequately supported implementation of the CAP. The following observations were noted:

1. Clear responsibility for upgrading CAP has only recently been established, and the leadership for this change originated with the Director of QA instead of line management.

2. Managers are preoccupied with short term priorities at the expense of focusing on longer term corrective actions.

3. Managers are not demanding quality analyses from event data. Typically, managers are not aware of the predominate event causal factors effecting the performance of their organizations. No feed back on the usefulness of event analysis reports has been received by the originator of the reports and at least one department head admitted to not using the report.

4. Frequent turnover of management is cited as a cause for "open circuited" corrective actions, i.e., when a manager leaves, the corrective action he has sponsored dies.

5. A mentality of "if Salem didn't invent it, it can't be the best" was mentioned several times as being a historical factor. Travel to witness programs at other plants is infrequent.

6. Post job critiques are infrequently performed. Outage High Impact Team critiques were identified as being weak.

RECOMMENDATIONS

- The following actions are recommended to improve the Corrective Action Program;

    1. Continue with the current plans to establish a corrective action program with single point accountability and strong management sponsorship. As soon as practical, this function should be migrated back into the line organization.

2. Consideration in developing the program for upgrading CAP should include as a minimum:

   i. A resource loaded plan which defines the development and implementation, including user training and a period for monitoring effectiveness.

   ii. Site visits to other plants identified as having strong corrective action programs.

   iii. Integration of all site corrective action processes into one data base, with one comprehensive set of causal factors.

- Senior management should put in place appropriate management systems that promote strong organizational alignment, high accountability, and appropriate management oversight. The current initiative to establish a biweekly meeting with performance indicators and attendance down through the department heads may represent the right approach but the design and implementation need rework. A visit to a plant where this is done well is a must.

- Commitment Tracking reports and performance indicators sorted by organization and indicating the types of commitments should be made available on a routine basis in an accountability forum involving senior management. These reports should track backlogs, aging, overdues, goals, use of extensions, and prioritization. Indicators should be accompanied by analyses and recovery plans.

- Adherence to the existing programs supporting causal factor analysis, e.g., the IR Program, is mandatory. Although not optimin, the current process must be followed. Management must insure that significant plant problems are entered into the system for evaluation. Hardware nonconformances must have bases for operability determinations.

OUTAGE PERFORMANCE

The assessment process of the Outage Performance consisted of interviews with personnel interfacing with the Outage Process. These interviews included personnel in Outage Management, Planning, Schedulers, Work Control, Quality Assurance, System Engineering, Mechanical Maintenance, Control Maintenance, Operations, Training, Design Engineering, and Materials.

OBSERVATIONS

- The PSE&G Nuclear Department procedure NC.NA-AP.ZZ-0055(Q) - Rev. 1 requires the establishment of Outage Milestones and Scope Control, but many of these controls have not been implemented. Many Design Change Packages are not issued with adequate time to properly plan and prepare for implementation in a properly scheduled Refueling Outage. Scope is continually being added and little or no Scope Control is being implemented.

  Engineering is starting to schedule the development of Design Change Packages. Up until this time very little scheduling has been done of the design process. Thus true estimates of how long it takes to develop the design and associated work packages and materials procurements have not been done. Because of the lack of these schedules Engineering has been unable to track its performance to ensure it meets scope cutoff dates.

  The Plan-Of-The-Day (POD) is a very large document and does not provide the basic information of the accomplishment of the past shift and what is the focus and critical path work to be done today. Many of those interviewed were not sure what the critical path was to getting the units back on line and very few could determine any required sequencing from the Outage POD.

- A high percentage of the Work Orders require correction or modification prior to the work beginning. The Work Orders are not issued to the Foremen/First Line Supervisor with adequate lead time to ensure that the planning is correct and the information in the package is ready for work.

  Crafts and First Line Supervisor are very frustrated in trying to provide information to work planning to improve future Work Orders because their changes are seldom incorporated.

  Work Planning is understaffed and is not producing the quality of Work Packages needed. Personnel are rushed and the quality of the package

varies widely depending on the planner. First Line Supervisors and the Work Control organization report that more than 30% of the Work Packages need to be corrected before the work orders go to the field.

The planning group does not have adequate time and manpower to review returned packages to incorporate recommended changes provided by the craftsmen and the First Line Supervisor. Crews and First Line Supervisors have, for all practical purposes, stopped providing improvements because they are not utilized.

The work Tagging process is very poor. This manual system requires numerous unnecessary trips to Work Control. A new automated electronic system is about ready to be placed in service at Hope Creek, but is not scheduled for Salem until some time later this year.

- The Outage Manager does not run the outage. The outage is run by the Operation Shift Supervisor and as the shifts rotate so does the perspective of the outage.

The present Outage Meetings have become a problem because upper management often changes or redirects daily activities of the outage at the 0800 meeting. Some of the First Line Supervisors and crews are now waiting for this change in direction before they start their daily work assignment.

Quite often the status that is given in the 0800 meeting is given to protect management's image rather than reflecting the true progress of the outage. These reports are usually corrected after the meeting in smaller one-on-one meetings.

Upper management does not always provide adequate management support to the Outage Manager during the outage.

The Outage Managers position in the management structure does not provide proper management authority to match the responsibility for running the outage.

Preparation and the direction of the outages has improved from the past but it is still poorly organized and does not function well. The shift to shift direction does not drive the outage. The interface between organization for transitional jobs is very poor. The contact points for various organization vary from shift to shift and critical path jobs are often delayed in the transition from one group to the next.

- High Impact Teams have been poorly organized. Team leaders are not selected properly and they are not trained on how to develop and run a High Impact Team. Salem HITs do not function well during the outage because of the lack of support and understanding and what HITs really are.

  Following the completion of major repetitive task and at the end of each outage a large number of ideas are discussed to improve the next outage but only a small number of these ideas are captured and incorporated

- Outages scheduling is a major problem. There appears to be inadequate focus or enforcement of the schedule.

  Support organizations seldom know what jobs are going to be run each day until they call the First Line Supervisor. Sometimes they don't find out until they are needed to support the work in the field and they become critical path until they can support the job. Jobs are delayed because different jobs end up trying to work in the same exact location or even on the same component.

  The only group that came close to following the schedule was the Main Turbine Work.

  The schedule is a record of what has been done and not what is to be done. First line supervisors are not given a schedule to follow. First line supervisors are not given the schedules for their work to review and comment. They feel that this must be done for them to properly organize their crews outage work.

  Inadequate time is taken by all levels of management to review and comment on the outage schedule resulting in no one having a high confidence in the schedule.

RECOMMENDATIONS

- Develop an outage scope control program that appropriately addresses late scope additions. Pre-outage milestones should be utilized during the planning phase of the outage and be directly incorporated into the present scope control procedure.

  Design engineering should schedule the development of total design packages to support the outage schedule.

- Revise the Plan-Of-The-Day to provide a more informative and user friendly one or two page document. Contact other nuclear facilities for document design.

- In order to develop and implement a planning, scheduling, and outage organization that would greatly enhance Salem's ability to plan, control, and implement all related activities during outages as well as normal operation, it is recommended that INPO be contacted for an outage assist visit.

- High Impact Teams (HIT) should be revised, organized, and operated consistently with the programs of other successful utilities.

- Senior Management should provide the leadership and guidance to insure that all schedules are adequately prepared, reviewed, and implemented.

- The Outage Manager must be placed in charge of the outage and Senior Management must support his position as being in charge.

Chronology of Events
for
EA 94-239

DATE:	NOTES
5/4/93	Ltr. to Northeast Utilities re: NOV and Proposed Civil Penalty of $100,000 and Demand for Information (NRC Investigation Report 1-90-001 - re: Paul Blanch)
11/3/93	Received DOL DD Finding: found in favor of alleger, claimed discrimination was a factor
11/4/94	OI Report No. 1-93-021R issued. H&I @ Salem. Licensee conducted an internal investigation of this matter, a report of which was issued on 4/2/93. **(There is no copy of this report in this file or Allegation File 93-0163)**
11/4/94	OI Report No. 1-93-021R referred to DOJ for prosecutorial review since actions of the three individuals constitutes potential deliberate violations of 10 CFR 50.5 (a)(1)
11/21/94	OI Report No. 1-93-021S issued.
1/4/94	Ltr. fm PSE&G to T. Martin: Response to 12/6/93 Chilling Effect Ltr. PSE&G appealed DOL DD finding in favor of alleger (11/3/93).
12/12/94	Collegial Meeting Scheduled
12/12/94	E-Mail fm Mark Satorius to D. Holody: DOJ has no objection to NRC pursuing enforcement action against license and/or all three individuals
1/11/95	Ltr. Tc Mr. Vincent Polizzi fm R. Cooper re: EC relative to NRC Investigation 1-93-021R

10/1/24

3

DATE:	NOTES
1/11/95	Ltr. To Mr. Lawrence Reiter fm R. Cooper re: EC relative to NRC Investigation 1-93-021R
1/11/95	Ltr. To Mr. Calvin Vondra fm R. Cooper re: EC relative to NRC Investigation 1-93-021R
1/11/95	Ltr. To Mr. Leon Eliason (PSE&G) fm R. Cooper re: EC relative to NRC Investigation 1-93-021R
1/18/95	Ltr. To Ross, Dixon, and Masback fm J. Gray (OE) re: Request for transcript of NRC interview with their client, Vincent J. Polizzi
1/19/95	Ltr. To Troutman Sanders fm J. Gray (OE) re: Request for transcript of NRC interview with their client Lawrence Reiter
1/27/95	Ltr. To R. Cooper fm Winston & Strawn re: Request for OI transcript and OI Report re: EC and Mr. Calvin Vondra
1/31/95	Ltr. To Ross, Dixon, & Masback fm J. Gray (OE) responding to incoming 1/18/95 Ltr. : encloses transcript.
2/1/95	Ltr. to Winston & Strawn fm J. Gray(OE): response to incoming 1/27/95 letter requesting transcript; transcript enclosed.
2/6/95	Ltr. Fm Ross, Dixon & Masback to K. Smith (OGC) re: Vincent J. Polizzi and the 2/8/95 Enforcement Conference; enclosing memo in support of Polizzi
2/6/95	2/8/95 Enforcement Conference Pre-Brief
2/8/95	Notes regarding Larry Reiter @ 2/8/95 Enforcement Conference

DATE:	NOTES
4/11/95	Ltr. To Mr. Calvin Vondra fm T. Martin re: NOV (NRC Investigation 1-93-021R)
4/11/95	Ltr. To Mr. Vincent Polizzi fm T. Martin re: Letter of Reprimand
4/11/95	Ltr. To Mr. Leon Eliason (PSE&G) fm T. Martin re: NOV and Proposed Imposition of Civil Penalty - $80,000
4/11/95	Ltr. To Mr. Lawrence Reiter fm T. Martin re: Enforcement Conference (NRC Investigation 1-93-021R) - no enforcement action warranted on this matter w/ regard to your actions
5/16/95	PSE&G response to our 4/11/95 NOV and proposed imposition of civil penalty - $80,000
5/20/95	Telephone Conversation Record of Mr. Calvin Vondra and D. Holody
5/21/95	Telephone Conversation (follow-up fm. 5/20/95) Record of Mr. Calvin Vondra and D. Holody
5/31/95	Ltr. To Mr. Leon Eliason (PSE&G) fm J. Gray(OE): Acknowledges receipt of 5/10/95 Ltr. and check for $80,000 in payment for the civil penalty
6/21/96	DOL ALJ Decision and Order on Remand: ALJ indicated that the record does not support a finding that there has been a violation of the settlement agreement.
8/7/96	DOL Administrative Review Board issues Order Establishing Briefing Schedule.

REGION I
PLANT STATUS REPORT

FACILITY: Salem Nuclear Generating Station
Units 1 and 2

Last Update: March 22, 1994

Update Approval: ____________________
Branch Chief

Update Approval: ____________________
Section Chief

CHANGES SINCE THE LAST UPDATE ARE DEMARCATED IN THE BORDER

CONTENTS

I. BACKGROUND

1. LICENSEE PARAMETERS

Utility:	Public Service Electric & Gas Company (PSE&G)	
Company Location:	Hancocks Bridge, NJ (18 miles Southeast of Wilmington, DE)	
County:	Salem	
	UNIT 1	UNIT 2
Docket No:	50-272	50-311
CP Issued:	September 25, 1968	September 25, 1968
Operating License Issued:	April 6, 1977	May 19, 1981
Initial Criticality:	December 11, 1976	August 2, 1980
Elec. Ener. 1st Gener:	December 19, 1976	May 29, 1981
Commercial Operation:	June 30, 1977	October 13, 1981
Reactor Type:	PWR 4-Loop	Same
Containment Type:	Large dry	Same
Power Level:	3411 MWt	Same
Architect/Engineer:	PSE&G/UE&C	Same
NSSS Vendor:	Westinghouse	Same
Constructor:	PSE&G/UE&C	Same
Turbine Supplier:	Westinghouse	Westinghouse (GE Generator)
Condenser Cooling Method:	Once-through	Same
Condenser Cooling Water:	Delaware River	Same

2. NRC ORGANIZATION

NRC Regional Administrator: (Region I, King of Prussia, PA)	Thomas T. Martin (Tel: 610-337-5000)
Division of Reactor Projects: (Region I)	Richard Cooper, Jr., Division Director (Tel: 8-610-337-5229) Wayne Lanning, Deputy Director (Tel: 8-610-337-5126) Edward C. Wenzinger, Branch Chief (Tel: 8-610-337-5225) John R. White, Section Chief (Tel: 8-610-337-5114)

NRC ORGANIZATION Continued:

Senior Resident Inspector:	Charles S. Marschall (Tel: 8-609-935-3850)
Resident Inspector:	Stephen T. Barr (Tel: 8-609-935-3850)
Resident Inspector:	Joseph G. Schoppy, Jr. (Tel: 8-609-935-3850)
Resident Inspector:	Todd H. Fish (Tel: 8-609-935-3850)
Project Engineer:	Robert J. Summers (Tel: 8-610-337-5189)
Project Manager:	James C. Stone, NRR (Tel: 8-301-504-1419)

3. LICENSEE ORGANIZATION

Management Personnel:

E. James Ferland	-Chairman and Chief Executive Officer
Lawrence R. Codey	-President and Chief Operating Officer
Robert J. Dougherty	-Senior Vice President, Electric
Steven E. Miltenberger	-Vice President and Chief Nuclear Officer
Stanley LaBruna	-Vice President, Nuclear Engineering
Joseph Hagan	-Vice President Operations and General Manager Salem Operations
Richard N. Swanson	-General Manager, Quality Assurance and Nuclear Safety Review
Lynn K. Miller	-General Manager, Nuclear Operations Support
Francis X. Thomson	-Licensing Manager
Lee Catalfomo	-Operations Manager
Michael P. Morroni	-Manager, Maintenance-Controls
Arthur Orticelle	-Manager, Maintenance-Mechanical
John W. Morrison	-Technical Manager
Terry L. Cellmer	-Radiation Protection/Chemistry Manager
Richard T. Griffith, Sr.	-Station QA Manager
G. Charles Munzenmaier	-Manager, Salem Station Planning
Peter Moeller	-Manager, Site Protection
Greg Mecchi	-Manager, Nuclear Training
Christopher Connor	-General Manager, Nuclear Support and Services

Workshifts

5 operations shifts, 2 working 12 hour shifts/day, 1 relief crew, 1 crew in training, 1 crew off.

Shift Complement:	TS minimum	Actual
	3 SRO	4 SRO
	4 RO	5 RO
	1 STA	1 STA (dual role SRO)
Non-licensed Operators	5	7 or 8

Maintenance Electrician/I&C	1	2
Chemistry/Rad. Prot.	1	2
Fire Brigade	5	6 (site fire brigade shared with Hope Creek)

4. OPERATOR LICENSING

a. Licensed Reactor Operators (Licenses Cover Both Units):

- Total number of active SROs: 29
- Total number of active ROs: 26
- Total number of certified instructors: 13

- In June 1993, NRC performed TI 117, "Licensed Operator Requalification Program Evaluation"; results were satisfactory.

- One simulator (modeled after Unit 2) located at the training facility in Salem, NJ, and used for Unit 1 and Unit 2 operator training and NRC administered licensing exams. PSE&G completed a major modeling upgrade package in the summer of 1993.

b. Other Licensed Operator Training / Performance / Staffing Concerns:

- Shift Supervisors began working 12 hour shifts during refuel outages conducted in the spring and summer of 1992, formally implementing that schedule in November 1992. The remainder of the shift complement maintained 8 hour shifts until April 1992, when, upon a union vote, they also adopted the 12 hour shifts for a 1 year trial basis. The reactor operators and equipment operators will be voting again in April 1993 as whether to permanently stay on 12 hour shifts.

II. PLANT PERFORMANCE DATA

1. CURRENT OPERATING STATUS (for period 10/1/93 to 3/1/94)

PSE&G shut down Unit 1 on October 1, 1993, to commence a 72 day refueling and maintenance outage. Prior to the shutdown, the unit had been on line since July 15, 1993, and operating at or near full power. Plant management extended the outage completion date (originally scheduled for December 17) because of emergency diesel generator (EDG) operability concerns. On December 2, 1993, a cracked cylinder liner in a Unit 2 EDG raised generic operability concerns for Unit 1 No. 1B EDG because of the similar liners installed in No. 1B. Operators restarted the unit on January 24; it automatically tripped from 100% power, on January 27 in response to a low water level condition in No. 14 steam generator. Operators restarted the unit on January 31, and operated the unit at power until it automatically tripped, from 100% power, in response to a loss of control power to the main turbine control system. PSE&G restarted the unit February 13, synchronized to the grid February 20, and has operated the unit at or near power through the end of the month.

PSE&G operated Unit 2 at or near full power throughout the fall, until December 3, 1993, when operators shut down the unit due to failure of a cylinder liner in the 2C EDG. After completion of repairs to the EDG, operators restarted the unit on January 3, 1994, and operated at full power until January 19, when the reactor engineering staff discovered that PSE&G had apparently operated Unit 2 in excess of 3411 megawatts (thermal). Since then, and through February, operators have maintained Unit 2 at 95% power.

2. RECENT SIGNIFICANT OPERATING EVENTS AND IDENTIFIED SAFETY CONCERNS

a. Significant Events (of last 12 months)

- Unit 1 automatically tripped on February 10, 1994, from 99% power, in response to a loss of 15 VDC power to the main turbine control system. The plant stabilized at normal operating pressure and temperature. PSE&G determined that the 15 VDC power supplies had tripped when their protective relays sensed an over-voltage condition. (See IR 50-272/94-01)

- Unit 1 automatically tripped on January 27, 1994, from 10% power, in response to a low water level condition in No. 14 steam generator. The cause of the trip was a level error controller in the control circuit for No. 14 steam generator feedwater regulating valve, which caused generator water level control to malfunction in the auto position. This malfunction generated the low water level condition and subsequent reactor trip. (See IR 50-272/94-01)

- Operators shut down Unit 2 on December 3, 1993, from 100% power, due to failure of a cylinder liner in 2C emergency diesel generator (EDG). PSE&G conservatively determined they had a basis for concern about the particular liner's reliability and consequently declared Unit 1 EDG 1B inoperable as well, since the 1B diesel had similar liners installed. (See IR 50-311/93-27)

- On November 2, 1993, operators declared an Unusual Event (UE) in response to a fire in a 230 volt lighting transformer in the Unit 2 turbine building. The fire brigade responded to the scene and extinguished the fire. The station was in the UE for approximately one hour. A loose electrical connection caused the fire. No personnel were injured and no safety-related equipment was affected. (See IR 50-311/93-23)

- On October 13, 1993, operators declared an UE in response to a fire in the Unit 1 No. 12 service water piping penetration bay. The shift supervisor notified PSE&G Fire Department, which responded to the scene and extinguished the fire. The station was in the UE for about 50 minutes. The fire was caused by sparks from a grinding activity, which ignited insulation from service water piping. Three contractor employees were treated for smoke inhalation; no equipment sustained damage. (See IR 50-272/93-21)

- On August 24, 1993, operators initiated a Technical Specification-required shutdown of Unit 1 in response to a degraded voltage on a cell in the 1C 125 volt battery. The need to shut down was relieved when the NRC exercised enforcement discretion in response to the licensee's request and associated justification. (See IR 50-272/93-20)

- On July 11, 1993, while the repairs to a faulty Unit 1 feedwater isolation protection relay were being performed, the main feedwater regulating valve for the No. 14 steam generator inadvertently went closed at 8:38 p.m., resulting in the water level in that steam generator dropping to a level sufficient to cause an automatic reactor trip. The licensee determined that the technician who was repairing the SSPS relay lifted an improper lead and caused the isolation of the No. 14 steam generator. The licensee additionally determined the root cause of the technician's error was inadequate detail and direction in the SSPS troubleshooting plan. Subsequent to the cause determination of the trip, PSE&G repaired the SSPS and commenced a reactor startup on July 15, 1993. The unit was returned to service on July 16, 1993. (See IR 50-272/93-19)

- On July 10, 1993, toxic gas release (ammonia) in the Unit 1 turbine building caused by a loop seal failure on the ammonia hydroxide storage tank due to overpressure. This apparently resulted from excessive ambient temperature conditions. The licensee will change the concentration of the ammonia hydroxide in the tank to increase the boiling point of the solution to prevent recurrence. (See IR 50-272/93-19)

- On June 8, 1993, Unit 1 automatically tripped following massive intrusion of sea-grass into the circulating water system suction. Four of five operating circulating water pumps tripped, causing a loss of main condenser vacuum, turbine trip, and subsequent reactor trip. (See IR 50-272/93-19)

- On May 28, 1993, Unit 2 was manually tripped by the operators per abnormal operating procedures when control bank "C", group 1 control rods (four rods total) fell into the core during reactor start up operations. At the time the operators were diluting the RCS to criticality for post-refueling startup. A card failure was attributed to a degraded solder trace in the rod control system, which led to the event. (See IR 50-311/93-81)

- On March 16, 1993, Unit 2 automatically tripped from 100% power due to a low-low level condition on the No. 24 steam generator. A failed pressure control switch in the condensate polishing system led to a low suction pressure condition for the No. 22 steam generator feed pump and subsequent feed pump trip, which caused the steam generator low level reactor trip. (See IR 50-311/93-08)

b. <u>Performance Indicator Data</u>

Units 1 and Unit 2:

- Performance indicators generally show good performance. Capacity factor numbers were low for 1993 due to back-to-back outages of Unit 1 and Unit 2 and shutdowns for potentially generic safety issues such as rod control and diesel generator cylinder liners. No other significant trends are evident in the statistical analysis.

c. <u>Recently Identified Technical Safety and Managerial Challenges (of last 12 months)</u>

- The NRC Resident Office continues to monitor and evaluate the licensee's efforts to improve plant material condition, repair and replace service water piping, upgrade the RMS system, complete actions relative to Appendix R requirements, issues associated with fire watches and security guards, personnel error reduction efforts, and procedure quality and compliance improvement efforts.

- Reviews were conducted and are planned for erosion/corrosion program.

- Service Water (SW) Leaks: Numerous SW through wall leaks continue to occur due to erosion and microbiologic induced corrosion attack of carbon steel piping. The licensee has a seven year pipe replacement project that will replace 95% (about 19,000 linear feet are safety related) of the safety related SW piping with 6% moly stainless steel. This project will continue through 1995 (two more refueling outages per unit). Currently, approximately 90% of

the safety related portion of the project has been completed, including the majority of the SW piping in containment. Based on NRC inspection, SW pipe replacement project is progressing satisfactorily as scheduled.

- Radiation Monitoring System (RMS) Problems: RMS problems have resulted in numerous ESF actuations and reportable events. Short term corrective actions were completed on both Unit 2 and Unit 1 during the 1992 refueling outages. These changes include electronic upgrades and a new uninterruptible power supply. Longer term actions (1993-4) include a complete system upgrade. Based on NRC inspection, the upgraded RMS operation to date has been satisfactory.

- Failure of Overhead Annunciators: On December 13, 1992, a Unit 2 operator discovered that the overhead annunciators had not been updating alarms for about 1 1/2 hours. This was the result of a member of the operating shift entering a keystroke combination into a remote control workstation that, when input through the wrong system port, prevented the system from updating alarms. An AIT was dispatched to the site and concluded: (1) the root cause was a failure to follow procedure for proper operation of the overhead annunciator system; (2) the design of the OHA system permitted the operator to inadvertently emulate the password-protected software without warning.

- Rod Control System: On May 27, 1993 Unit 2 operators experienced several problems with the rod control system. The most significant event was that during an attempt to insert Shutdown Bank "A", one control rod actually withdrew 15 steps of travel. An AIT was dispatched to the site and concluded: (1) the root cause was an introduction of static charges into the solid state electronic components which caused system damage; (2) damage was also caused by voltage spikes originating from "back EMF" in the system's electro-mechanical step counters (the suppression diode installed to mitigate this previously-known phenomenon was disabled due to a failed pin connector on the affected circuit card).

  At 5:12 p.m. on July 18, 1993, Salem Unit 2 Control Bank D (8 control rods) began stepping inward at a rate of 72 steps per minute, but only moved a few steps before being detected by operators. At the time, Unit 2 was at 100% power with the control rods in automatic. The operator, finding no apparent cause for the rod insertion, positioned the rods in manual control, which stopped the rod movement. The operators performed all actions per their abnormal rod movement procedure (AB-ROD-0003) and were still unable to positively identify the cause. The licensee installed monitoring instrumentation on the inputs to the automatic rod control signal summator and at 11:40 p.m. on July 18, returned rod control to automatic.

  At 11:24 a.m. on July 21, 1993, the licensee again experienced the same phenomenon on Unit 2. As in the previous occurrence, the operator quickly evaluated the situation and appropriately placed the rods in manual control. In both cases the rods only moved inward a few steps (2 and 4 steps

respectively). Current traces on the signal summator input revealed no change from the nuclear instrument (NI) or turbine impulse pressure, but some spiking from the average temperature (Tave) and reference temperature (T ref) input. Together these four signals are the input signals to the automatic rod control system. On July 21, the licensee placed additional monitoring instrumentation on the output of the signal summator, output of the "rod in output" signal comparator, and individually on all four Tave channels.

On July 22, 1993, during I&C troubleshooting, the licensee was able to identify a fault in the signal summator, which erroneously produced a high rod inward demand output for a relatively small temperature error input.

- Switchyard Modifications: During the recent outage on Unit 1, PSE&G implemented an extensive design change package involving modifications to the Salem switchyard. These modifications increased voltage recovery on vital and group buses during bus transfers, provided load growth capacity, removed the Salem circulating water system pump motor feeds from the Hope Creek switchyard, improved voltages in both Salem plants, provided margin for short circuit capability, and improved plant reliability. Major components added included two 500/13.8 kv transformers, four 13.8/4.16 kv transformers, four 13.8 kv breakers, and 4.16 kv switchgear for the circulating water system bus.

- Unit 2 Sustained Operation of Greater Than 100% Power: Suspected root cause is erosion of the feedwater flow nozzles resulting in incorrect online calorimetric data. Upon discovery, licensee immediately reduced power for both units, and began adjusting instrument setpoints to insure conservative operation. Licensee is pursuing determination of the exact power level and the effects on the UFSAR Chapter XV analyses. They expect resolution by mid-April 1994.

- Emergency Diesel Generator Cylinder Liner: This caused Salem 2 to shut down as a result of a cracked liner, and delayed Salem 1 to delay startup from the refueling outage. The licensee could not find a clear root cause. The suspected root cause was dimensional tolerance problems with liners distributed by Canadian Allied Diesels. PSE&G determined that only two liners have ever failed, including the Salem liner, in a population of tens of thousands of liners in use world wide (including locomotives and ships).

3. ESCALATED ENFORCEMENT ACTIVITIES

- The NRC issued a Level III Violation on March 8, 1994, documented in NRC Inspection Report 50-272 and 311/93-23; 50-354/93-25. The violation was based on multiple examples of PSE&G's failure to follow procedures and their failure to properly control safety-related activities.

4. IPE INSIGHTS

- The Salem IPE was submitted to the NRC in July 1993, and is still under NRC review.

III. ANALYSIS/ASSESSMENT

1. PREVIOUS SALP RATINGS AND OVERVIEW

a. Previous SALP Ratings

Functional Area	December 28, 1991	June 19, 1993
Operations	2	2
Maintenance/ Surveillance	2	2
Radcon	2, Imp	1
Emergency Preparedness	1	1, Declining
Security	1	1
SA/QV	2	2
Engineering & TS	2	2

Current assessment period: June 20, 1993 to December 10, 1994.

b. SALP Overview (derived from the summary paragraph of each SALP section):

OPERATIONS

On July 29, 1993, the SALP board met to discuss PSE&G's performance at Salem during the period from December 29, 1991 to June 19, 1993. The board concluded that the licensee had operated the Salem units safely and that operator response to operational events was excellent. The overall performance in the Operations area was good. However, weaknesses were noted in the decisions to restart Unit 2 following the rod control system problems, in the failure to follow procedures resulting in the loss of Unit 2 annunciators, and in the inadequate oversight of the fire protection program.

MAINTENANCE/SURVEILLANCE

The board concluded that the Salem maintenance and surveillance programs contributed to the safe operation of the two units during the assessment period. In general, a declining number of personnel errors in both maintenance and surveillance indicated improving performance. However, the number of transients induced by component failures and the significant problems with the rod control system raise questions regarding the overall effectiveness of the maintenance and engineering support functions.

RADIOLOGICAL CONTROLS

PSE&G continued to implement effective radiological controls and ALARA programs during this period. The SALP board noted improvements in this functional area including strong management support and oversight. Quality Assurance audits in this area were of very good quality.

EMERGENCY PREPAREDNESS

The SALP board determined that PSE&G maintained a generally strong and effective emergency preparedness (EP) program. However, the board was concerned with an apparent decline in the ability of the licensee to make correct initial Protective Action Recommendations during training, drills and annual exercises. This concern resulted in the board's assessment of a declining trend for this area. The board also concluded that PSE&G continued to maintain an effective and performance-oriented security program during this period. Overall, licensee performance in both EP and security remained excellent.

ENGINEERING AND TECHNICAL SUPPORT

Engineering and technical support organizations provided good support for refueling and maintenance outages, and strong performance in addressing day-to-day problems. The SALP board noted that training programs for engineering personnel were excellent but that weaknesses were observed in the licensee's non-conformance, erosion/corrosion, and fire protection programs. Although the root cause training program was viewed as a strength, the board noted that the threshold for initiating actual root cause investigation was not clear or consistent.

PSE&G management continued to provide generally effective management support. Significant Event Response Team (SERT) reviews of major events have been effective. However, the board noted that in several instances, PSE&G failed to initiate adequate root cause evaluation or assessment of abnormal conditions. NRC interaction with PSE&G management was needed in a number of cases in order for full evaluation and corrective action to be taken in a timely manner. Once initiated, comprehensive assessment, root cause analysis and effective corrective actions were implemented. Outage planning and training programs in all areas were considered strengths.

2. LICENSEE RESPONSE TO PREVIOUS SALP FUNCTIONAL AREA WEAKNESSES / RECENT LICENSEE PERFORMANCE TRENDS (in the last year)

- OPERATIONS

&G continues to safely operate the units. Operator plant knowledge and response to events remains strong, however, operator response has been less than thorough regarding indications of stuck-open RHR check valves, indications of a possible leaking RHR pressure isolation valve, and a case of indeterminate hotwell level.

Recent management changes included the naming of a new Operations Manager in September 1993, and two new Operations Engineers in January 1994. The licensee intends to pursue full unitization of the Salem operating crew shifts.

- MAINTENANCE AND SURVEILLANCE

Although maintenance and surveillance activities remain generally good, as exhibited by strong Maintenance Department performance in response to the December 1993 EDG cracked cylinder liner issue, the recent Unit 1 refueling outage was marked by multiple examples of poor work control practices and multiple examples of failure to follow procedures.

In order to improve overall performance and response to emergent issues, PSE&G has reorganized the Maintenance Department. Recent changes include replacing the single Maintenance Manager role with three new positions: 1) Mechanical Maintenance Manager, 2) Controls Maintenance Manager, and 3) Planning Manager. PSE&G is also pursuing unitization in these departments.

- ENGINEERING AND TECHNICAL SUPPORT

Both Salem system engineering and PSE&G nuclear engineering have continued to provide good engineering support for plant operations.

An NRC observation related to the Salem rod control issue was that the initial troubleshooting efforts lacked clear leadership and delegation of responsibilities. This resulted in the efforts narrowly focusing on the most recent system malfunction without adequate attention to the repetitive nature of the failures and the need to determine and correct the root cause. The failure of PSE&G to determine the root cause of the failures resulted in numerous aborted startup attempts. The team did observe significant improvements in the control of troubleshooting and root cause determination during the inspection.

- PLANT SUPPORT

The NRC noted that PSE&G continued to perform at a noteworthy level in the area of radiological protection through the end of 1993, especially during the recent Unit 1 refueling outage.

The licensee's annual partial-participation emergency preparedness exercise was conducted on June 23, 1993. On-site response to the simulated emergency was very good. An exercise strength was Emergency Response Manager command and control. No exercise weaknesses were identified. Significant areas for potential improvement were maintenance team tracking from the Operational Support Center and public address system operability in the Technical Support Center.

The PSE&G security program continues to be effectively directed towards public health and safety. A strike by the security force was narrowly averted when a new labor agreement was reached in November 1993.

- SAFETY ASSESSMENT/QUALITY VERIFICATION

In July 1993, the licensee formed a Comprehensive Performance Assessment team (CPAT) which conducted a special assessment of safety issues and recent plant events using an integrated MORT investigatory analysis. The CPAT developed comprehensive root causes for these events, and the licensee has formed task teams charged with developing corrective actions. PSE&G has held periodic meetings with the NRC to discuss CPAT findings, and the NRC continues to monitor licensee progress in this area.

In February 1994, PSE&G Vice President of Nuclear Operation (VP-NO) assumed the collateral role of General Manager of Salem Operations. The licensee also initiated other management changes under the VP-NO and intends to pursue unitization of the Salem units. PSE&G has implemented these changes in order to achieve sustained improvement in the area of Salem performance.

3. LICENSEE PERFORMANCE STRENGTHS AND WEAKNESSES *

Salem performance continues to be inconsistent.

- Capacity factor has been low due to refueling outages at both units and forced outages due to rod control problems, and diesel liner concerns.

Strengths:

- The licensee continues to increase resources for a material condition improvement program. The NRC has observed noticeable improvement in the material condition of the plant, indicating that the licensee has been earnest in the implementation of improvements.

- The Procedure Upgrade Project (PUP) was closed out in September 1993. A large majority of procedures were reviewed and upgraded, and procedure maintenance has been made the responsibility of the Technical Department.

- Material condition

- Procedure quality

- Radiation protection program implementation

- When problems or conditions are self-identified and self-detected, event response and root cause determination are through and comprehensive, particularly when the matter is the subject of NRC attention. In other cases, the licensee's performance is considered weaker, as identified below.

- PSE&G has responded to identified performance and management weaknesses relative to approch to problem resolution by initiating the following actions:

- Replacing the Salem General Manager with the Vice President, Nuclear Operations until the licensee's program changes are in place;

- Verifying the effectiveness of numerous supervisors and managers and changing the incumbent when deemed appropriate

- Pursuing unitization of the maintenance, operations, and planning organizations,

- Implementing the existing performance assessment tools to improve accountability from the highest levels of management down to rank and file workers,

- Forming dedicated teams to implement the corrective actions developed in response to the CPAT findings.

Weaknesses:

Salem performance has been weak in:

- Control of maintenance

- Recognition of the need to due root cause determination,

- Corrective action effectiveness due to inadequate root cause assessment

- Inadequate approach to problem resolution (i.e., general tendency to fix problems or conditions without assessment or understanting of causal factors. Examples include, but are not limited to the licensee's initial response to cracked diesel liner issues, failure to identify elevated reactor power in 1992, and failure to recognize generic implication of rod control problems

4. NRC TEAM INSPECTIONS WITHIN THE LAST YEAR

Area/Date	Findings
EDSFI Assessment August 16 - September 3, 1993	Licensee-contracted EDSFI has been completed. The NRC assessment of the licensee EDSFI identified a number of minor concerns; but, concluded overall that the licensee's assessment was good.
Augmented Inspection Team (AIT) June 5 - July 2, 1993	An AIT was formed to review and evaluate the circumstances surrounding a problem with the Unit 2 rod control system. The components within the control circuitry that led to rod withdrawal when operators were demanding rod insertion.
Appendix R Inspection May 17-21, 1993	Identified concerns with Kaowool and 3-M fire wrap material. Also weaknesses in safe shutdown outside the control room and lighting. Re-evaluation to occur during July 1993.

5. PLANNED TEAM INSPECTIONS

SWSOPI	Date and scope to be determined.
DET/OSTI/IPAT??	(Does this team exist yet?)

IV. INSPECTION PROGRAM STATUS

1. STATUS OF INSPECTIONS

The inspection program status is reflected in attached MIPS report #2. The data is current as of the date of the MIP. The MIP indicates that inspection program is on-track with the planned resource allotment; no significant shift in inspection activities is warranted.

2. PROPOSED CHANGES TO MIP

- Unit 1

A. DRSS -

B. DRS -

C. DRP

- Unit 2

A. DRSS -

B. DRS -

C. DRP -

3. SIGNIFICANT ALLEGATIONS AND INVESTIGATIONS

- There are eight open significant allegations at Salem. (two are common with Hope Creek)

Three allegations are related to harassment and intimidation of licensee personnel, up to and including allegations of promotion denial due to "whistleblowing." One of the allegations asserts that the Offsite Safety Review Group is not performing its functio[illegible] in accordance with technical specifications. OI is actively reviewing these cases.

A fourth allegation asserted that the main security access center at the Salem/Hope Creek site was not manned as required by the NRC approved security plan. DRSS is scheduled to conduct a routine security inspection in March 1994 and will review this matter.

The fifth allegation concerns an operator wrongdoing issue. During and subsequent to the Overhead Annunciator (OHA) AIT in early 1993, neither of the two operators in the control room at the time of the incident admitted to any manipulation of the OHA system, even though clearly operator involvement was a contributor to the event. DRP is reviewing the licensee's investigation and followup into this matter and will determine this issue's resolution on the basis of that review.

The sixth allegation involves a technical question that suggests that HVAC ductwork integrity may not be assured under dynamic loading of new fast-acting curtain fire dampers. DRP is reviewing test procedures and results while DRS is scheduled to review the matter during the next routine fire protection inspection.

The seventh allegation regards evidence that the Rod Control problems experienced by the plant (and followed up by the AIT) occurred during startup testing at the Zion nuclear station, even though Westinghouse representatives denied that the problem had ever occurred before. OI has opened an investigation into this case and is currently reviewing the matter.

The final allegation concerns 6 technical issues raised regarding the environmental qualification of equipment. Upon agreement of the alleger, this matter will be referred to the licensee for resolution. Otherwise, DRS will followup it up.

4. OPEN ITEM STATUS

BACKLOG/No. GREATER THAN 2 YRS

(Unit 1 and 2 - Common) 57/6

NOTE: The large number of open items is due to the issuance of an Appendix R/Fire Protection Team Inspection Report in October 1993 and an EDSFI Team Inspection Report in November 1993.

5. OUTSTANDING LICENSING ISSUES

- GL 89-10 (MOV) - technical differences between NRC/PSE&G. (Hope Creek also)
- EDG amendment - meeting held May 11, 1992 to resolve issues.
- TS amendment to resolve AFW/containment spray issue (see Section II.2.a).
- Increase in surveillance test intervals and AOT for reactor trip and ESFAS.
- Install new digital feedwater control system.
- Evaluation of Control Room Design Deficiencies that were not corrected.

- Bulletin 88-08 (Thermal Stress in Piping Systems Connected to the RCS) - licensee is revising their response.

6. LOCAL/STATE/EXTERNAL ISSUES

a. NJ DEPE/BNE

- Now providing input/comments on all PSE&G licensing change requests.
- Letter regarding Salem RMS (see Section II.2.a).
- Provided comments on recent SALP report.
- High interest in resident inspection accompaniment.
- Continuing interest in Salem cooling tower issue: When Salem's renewable variance for the use of the Delaware River as a heat sink came up for renewal in 1984, New Jersey environmentalists appealed to the state to not renew the variance. In 1990, NJ DEPE issued a "draft order" requiring PSE&G to build two cooling towers to support the Salem units' operation. PSE&G responded to the state's order with a 56-volume comment, and the issue is currently under review by NJ DEPE. Recent NJ DEPE decision not to require cooling towers.
- State inspector accompanied AITs that reviewed Salem 2 loss of OHA system and RCS.
- Recent letter (6/29/93) concerning digital feedwater modifications to be performed the next two refueling outages.

b. Other (Media Interest)

- Minimal interest in SALP Management Meeting.
- Large interest in AIT (Unit 2 TG failure) exit meeting.
- Smaller interest in two AITs (Unit 2 Loss of Alarms and rod control problems) exit meeting.

SALEM SITE SIGNIFICANT OPERATING EVENTS

- November 9, 1991, Salem Unit 2 turbine overspeed event caused by insufficient preventive maintenance and surveillance, failure to follow procedures, and inadequate root cause analysis. **(AIT, IR 50-311/91-81, Severity Level III, no CP)**

- December 13, 1992, Salem Unit 2 loss of overhead annunciator event caused by operator failure to follow procedures for Remote Configuration Workstation; and less than adequate design specifications for overhead annunciator alarm and warning features. **(AIT, IR 50-272&311/92-81)**

- May 24 - June 4, 1993, Several aborted Salem Unit 2 startup attempts due to rod control problems. Inadequate root cause analysis was a principal contributor. Licensee demonstrated poor problem resolution technique and ability. **(AIT, IR 50-272&311/93-81)**

- April 7, 1994, Salem Unit 1 trip from 25% due to operator error (Operators reduced power to 10% to compensate for grass intrusion, which enabled the 25% low power trip setpoint. To restore lower than normal Tave, operators withdrew some control rods which increased power in excess of 25%, which resulted in trip. Trip was complicated when two MSIVs and two FW isolation valves failed to close; and two turbine driven feed pumps failed to trip. SI actuated, PRT rupture disk blew-out, and the licensee declared a UE followed by an ALERT. AIT dispatched. Consequently, escalated enforcement action was taken (Four Severity Level IIIs with a $500,000 CP). General cause involved ineffective corrective action for pre-existing equipment deficiencies that provided challenges to operators (MS10), inadequate operator command and control, and ineffective management communication of expectations to the staff, and poor operator performance issues. **(AIT, IR 50-272&311/94-80)**

- Most significant event(s) is the combination of the May 1995 shutdown of Unit 1 and the June 1995 shutdown of Unit 2. (see attached)

M/130

Salem Shutdown of 1995

- In December 1994, one of three switchgear supply fans (no. 12 fan) failed in service. These fans provide cooling to the emergency switchgear during accident conditions. Their loss could jeopardize the operability of equipment connected to the 4 KV emergency busses. The licensee did not recognize the significance of this failure because this loss resulted in an inability to withstand a future single failure. As such, repair activities proceeded on a normal vice a priority basis. When the no. 13 switchgear supply fan failed on May 12, plant staff could not justify emergency bus operability, and found that the subsequent fan failure constituted an unreviewed safety question. However, the plant engineering staff pursued justifying continued operation. Operators rejected their conclusion and shut the plant down.

- On January 26, 1995, as operators decreased flow from no. 22 Residual Heat Removal (RHR) pump into the reactor vessel, a Unit 2 RHR minimum recirculation flow bypass valve (22HR29) failed to open, and had to be manually opened. They initiated a work order stating that the valve failed to open automatically, but considered the valve operable without any basis. On February 9, 1995, an additional Unit 2 minimum recirculation flow bypass valve (21HR29) failed to open automatically in response to a low flow condition. Again, a work order was initiated to investigate and repair. No significant priority was assigned to the work orders, and they became part of the licensee's maintenance backlog. Thus, both RHR systems remained inoperable from February 9, until June 6, 1995. During a review of open safety-related work orders, plant staff identified that the work orders for the 21 and 22 RH29 valves documented unresolved degraded conditions potentially affecting RHR pump operability. However, the licensee continued to believe that both RHR systems were operable. Eventually, after rigorous questioning by the Senior Resident Inspector, the RHR systems were declared inoperable on June 7, and Unit 2 was shutdown. This chain of events indicated weakness in the questioning attitude of the operators and management, as well as, fundamental problems with operability determinations and management oversight of operational activities.

- On June 9, 1995, Chief Nuclear Officer committed to maintain the Salem units in shutdown condition pending the completion of the following:

  1. The performance of a Significant Event Response Team (SERT) review of the circumstances leading to, and causing the Salem Unit 2 reactor trip, and communication of findings to the NRC.

2. The performance of a special team review of long-standing equipment reliability and operability issues, including corrective maintenance and operator work-arounds; the effectiveness and quality of the management oversight and review of these matters; and communication of findings to the NRC.

3. A meeting at the Salem facility with NRC representatives to describe, discuss and gain NRC agreement on the scope and comprehensiveness of PSE&G plan for the performance of a operational readiness review in support of startup of each Salem unit, including the description of the issues that are required to be resolved prior to restart.

4. The performance of an operational readiness review at each Salem unit.

5. Meetings with NRC representatives to describe the outcome and conclusions of the operational readiness review for each Salem unit; and to gain NRC agreement that each Salem unit is sufficiently prepared to restart.

- As a result of continued performance deficiencies, weak management oversight, and ineffective corrective actions coupled with the Technical Specification (TS) required shutdowns of both units, NRC Region I issued a Confirmatory Action Letter (CAL) on June 9, 1995. This CAL delineated licensee commitments that must be satisfied prior to the restart of either Salem unit. The Salem Assessment Panel (SALP) was chartered and had been tasked with monitoring the licensee's restart plans in accordance with NRC Manual Chapter 0350. Salem has put in place a new management team and preliminary indications are that it has been effective at improving the safety focus of the Salem organization.

- Collectively, these two events which revealed significant management weaknesses, along with other fundamental demonstrated weaknesses in the licensee's corrective program, resulted in the issuance of six Severity Level III violations with an aggregated civil penalty of $600,000. (IR 50-272&311/95-10)

REGION I
PLANT STATUS REPORT

FACILITY: Hope Creek Nuclear Generating Station

Last Update: March 22, 1994

Update Approval: ____________________
Branch Chief

Update Approval: ____________________
Section Chief

CHANGES SINCE THE LAST UPDATE ARE DEMARCATED IN THE BORDER

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The attached status report has not been made public. Do not disseminate or ~~discuss its~~ contents outside NRC. Treat as "OFFICIAL USE ~~ONLY~~".

CONTENTS

I. BACKGROUND

1. LICENSEE PARAMETERS

Utility:	Public Service Electric & Gas Company (P^-^&G)
Company Location:	Hancocks Bridge, NJ (18 miles Southea… Wilmington, DE)
County:	Salem
Docket No:	50-354
CP Issued:	November 4, 1974
Operating License Issued:	July 25, 1986
Initial Criticality:	June 28, 1986
Elec. Ener. 1st Gener:	August 1, 1986
Commercial Operation:	December 16, 1986
Reactor Type:	BWR 4/5
Containment Type:	Mark I GE
Power Level:	1067 MWe; 3293 Mwt
Architect/Engineer:	Bechtel
NSSS Vendor:	General Electric
Constructor:	Bechtel
Turbine Supplier:	General Electric
Condenser Cooling Method:	Natural Draft Cooling Tower
Condenser Cooling Water:	Make-up from Delaware River

2. NRC ORGANIZATION

NRC Regional Administrator: (Region I, King of Prussia, PA)	Thomas T. Martin (Tel: 610-337-5000)
Division of Reactor Projects: (Region I)	Richard W. Cooper, Division Director (Tel: 8-610-337-5229) Wayne D. Lanning, Deputy Director (Tel: 8-610-337-5126) Edward C. Wenzinger, Branch Chief (Tel: 8-610-337-5225) John R. White, Section Chief (Tel: 8-610-337-5114)

NRC ORGANIZATION Continued:

Senior Resident Inspector:	Charles S. Marschall (Tel: 8-609-935-3850)
Resident Inspector:	Stephen T. Barr (Tel: 8-609-935-3850)
Resident Inspector:	Joseph G. Schoppy, Jr. (Tel: 8-609-935-3850)
Resident Inspector:	Todd H. Fish (Tel: 8-609-935-3850)
Project Engineer:	Robert J. Summers (Tel: 8-610-337-5189)
Project Manager:	James C. Stone, NRR (Tel: 8-301-504-1419)

3. LICENSEE ORGANIZATION

Management Personnel:

E. James Ferland	-Chairman and Chief Executive Officer
Lawrence R. Codey	-President and Chief Operating Officer
Robert J. Dougherty	-Senior Vice President, Electric
Steven E. Miltenberger	-Vice President & Chief Nuclear Officer
Stanley LaBruna	-Vice President, Nuclear Engineering
Richard N. Swanson	-General Manager, Quality Assurance and Nuclear Safety Review
Francis X. Thomson	-Licensing Manager
Joseph J. Hagan	-Vice President Operations and General Manager Salem Operations
Robert J. Hovey	-General Manager - Hope Creek Operations
Stephen L. Funsten	-Maintenance Manager
James Clancy	-Technical Manager
Martin Prystupa	-Radiation Protection Manager
Kim Maza	-Chemistry Manager
Open	-Station QA Manager
George C. Connor, Jr.	-General Manager, Nuclear Services
Greg Mecchi	-Manager, Nuclear Training
Peter A. Moeller	-Manager, Site Protection

Workshifts

5 operations shifts, 2 working 12 hour shifts/day, 1 relief crew, 1 crew in training, 1 crew off.

Shift Complement:	TS Minimum	Actual
	2 SRO	3
	2 RO	2-4, depending on shift
	1 STA	1 (dual role SRO)
Non-licensed Operators	2	3 (some shifts have 4 or 5)
Maintenance Electrician/I&C	1	2

Chemistry/Rad. Prot.	1	2
Fire Brigade	5	6 (site fire brigade shared with Salem)

4. OPERATOR LICENSING

a. Licensed Operator Program Status:

- SRO/RO licenses:

Total Licensed Operators:	45
Total Number of Active SROs:	27
Total Number of Active ROs:	18
Total Number of Certified Instructors:	13

- In June 1993, NRC performed TI 117, "Licensed Operator Requalification Program Evaluation"; results were satisfactory.

- Licensed operator training performance appears satisfactory given the high pass rate on initial license exams.

b. Other Licensed Operator Training / Performance / Staffing Concerns:

- None

II. PLANT PERFORMANCE DATA

1. CURRENT OPERATING STATUS (for period 10/1/93 to 3/1/94)

Operators manually scrammed Hope Creek on December 1, 1993, due to severe arcing and exciter ring damage on the main generator. Prior to the scram, the plant had been on-line for 105 consecutive days. The licensee determined the problem with the main generator was the result of the installation of acceptable, although not preferred, brush assemblies on the exciter. PSE&G subsequently revised procurement and installation procedures to prevent recurrence, replaced the affected brush assemblies and restarted the unit on December 5, 1993.

Following the restart, Hope Creek remained at power until March 5, 1994, when operators took the unit off-line in order to commence Hope Creek's fifth refueling outage. The outage is scheduled to last 49 days.

Other small power reductions were performed throughout the period to perform maintenance and testing activities.

2. RECENT SIGNIFICANT OPERATING EVENTS AND IDENTIFIED SAFETY CONCERNS

a. Significant Events (of last 12 months)

- On May 13, 1993, a partial loss of off-site power caused the unit to reduce power to 40%. Subsequently, on May 16, 1993, the reactor scrammed from 60% due to high reactor pressure during weekly turbine stop valve testing. The turbine control and intercept valves closed unexpectedly causing a rapid turbine steam demand decrease and resultant reactor pressure increase. An EHC agastat relay associated with the speed control circuit failed. This failure caused the EHC system to react to a false high turbine speed signal, closing the control and intercept valves, and resulting in a reactor pressure increase. (See IR 50-354/93-11)

- During the previous operating cycle the brushes on the generator end of the reactor coolant system recirculation pump motor generator (MG) sets exhibited abnormal wear. Consequently, on August 21, 1993, Hope Creek operators reduced plant power to approximately 45% power in order to alternately remove each recirculation pump from service so that maintenance could be performed on the MGs. While in single loop operation Hope Creek maintenance technicians replaced the generator brushes on each MG set while its respective recirculation loop was idle. Once the MG set maintenance work was completed, Hope Creek operators restored the recirculation system to its normal configuration and returned plant power to 100%. (See IR 50-354/93-20)

- Operators manually scrammed Hope Creek on December 1, 1993, due to severe arcing and exciter ring damage on the main generator. Prior to the scram, the plant had been on-line for 105 consecutive days. The licensee determined the problem with the main generator was the result of the installation of acceptable, although not preferred, brush assemblies on the exciter. PSE&G subsequently revised procurement and installation procedures to prevent recurrence, replaced the affected brush assemblies and restarted the unit on December 5, 1993. (See IR 50-354/93-27)

b. Performance Indicator Data

- Performance indicators generally reflect good performance. Short term improvements in automatic scram and equipment forced outage rates were noted.

c. Recently Identified Technical Safety and Managerial Challenges (of last 12 months)

- Vessel Water Level Instrumentation Modification: In response to NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," PSE&G initiated steps to incorporate certain modifications to their vessel water level system. A letter from the facility to the Commission, NLR-N 93126, dated July 30, 1993, describes PSE&G's short term compensatory actions and the hardware modifications planned for the next cold shutdown. The scheduled non-outage work is complete. The actual tap into the CRD and water level instrument lines was accomplished during the outage following the December 1, 1993, manual scram.

  Based on NRC inspection to date, the water level instrumentation modification proceeded per engineering's schedule, and observed hardware installation was of high quality, based on no re-work being necessary. Engineering's management of the modification was strong and produced good results.

- Core Shroud Inspection and Jet Pump Hold-Down Beam Replacement: PSE&G intends to respond to both of these generic issues during the Hope Creek fifth refueling outage, which commenced on March 5, 1994. The licensee is following General Electric guidance on both issues; a full in-service inspection of all welds in the beltline region of the core shroud will be conducted and the hold-down beams for all 20 jet pumps will be replaced with new beams of the preferred heat-treatment method.

3. ESCALATED ENFORCEMENT ACTIVITIES

- There is one pending escalated enforcement activity regarding inaccurate and incomplete information relative to the requirements of 10 CFR 50.9, submitted by the licensee on March 8, 1991, in response to Generic Letter 89-10. An enforcement conference was held with the licensee on December 20, 1993. Discussion with NRR and the Office of Enforcement is on-going in order to resolve technical issues before the issue is presented to the Commission.

4. IPE INSIGHTS

- The Hope Creek IPE is under review and due for completion in April 1994.

III. ANALYSIS/ASSESSMENT

1. PREVIOUS SALP RATINGS AND OVERVIEW

a. Previous SALP Ratings

Functional Area	December 28, 1991	June 19, 1993
Operations	1	1
Maintenance/ Surveillance	2, Imp	1
Radcon	1	1
Emergency Preparedness	1	1, Decl
Security	1	1
SA/QV	1	1
Engineering & TS	2	2, Imp

Current assessment period: June 20, 1993, to December 10, 1994

b. SALP Overview (derived from the summary paragraph of each SALP section):

OPERATIONS

On July 29, 1993 the SALP board met to discuss PSE&G's performance at Hope Creek during the period from December 29, 1991 to June 19, 1993. The board concluded that the licensee had operated Hope Creek in a safe and conservative manner. Operator training was a strength and the operator error rate remained low, contributing to a decreased reactor scram rate. PSE&G provided effective management oversight and attention to all operational activities. A weakness was noted in management's oversight of firewatch program activities, a common function affecting Salem and Hope Creek.

MAINTENANCE/SURVEILLANCE

PSE&G demonstrated superior results in maintenance program implementation at Hope Creek, and very good results in surveillance testing. Continued management involvement in improving program performance and correcting identified problems was evident. The SALP board also noted specific improvements in procurement and material control during this period.

RADIOLOGICAL CONTROLS

The licensee continued effective implementation of their state-of-the-art radiological controls program. The SALP board noted that management support and control, staffing levels, quality assurance oversight, and ALARA were program strengths.

EMERGENCY PREPAREDNESS

The SALP board determined that PSE&G maintained a generally strong and effective emergency preparedness (EP) program. However, the board was concerned with an apparent decline in the ability of the licensee to make correct initial Protective Action Recommendations during training drills and annual exercises. This concern resulted in the board's assessment of a declining trend for this area. The board also concluded that PSE&G continued to maintain an effective and performance-oriented security program during this period. Overall, licensee performance in both EP and security remained excellent.

SAFETY ASSESSMENT/QUALITY VERIFICATION

The licensee continued to perform well in the area of Safety Assessment and Quality Verification during this period. First line supervision and management oversight were very good, as was the independent review provided by the On-site and Off-site Safety Review Groups and by Station Quality Assurance. Performance by individuals was strong, as evidenced by a reduction in the personnel error rate.

ENGINEERING AND TECHNICAL SUPPORT

Engineering and technical support for the Hope Creek station improved during this SALP period. The board noted improvements in the licensee's program for controlling design changes and plant modifications, MOV program implementation, training of the engineering staff, and reduction of engineering backlogs.

2. LICENSEE RESPONSE TO PREVIOUS SALP FUNCTIONAL AREA WEAKNESSES / RECENT LICENSEE PERFORMANCE TRENDS (in the last year)

- OPERATIONS

Hope Creek operators continued to operate the plant in a conservative and safety-conscious manner, with operator response to events a notable strength. Effective management oversight is evident, although the NRC is monitoring operator sensitivity to the proper use of 10 CFR 50.59 when changes to plant configuration are made. The licensee properly resolved NRC concerns with the site firewatch program.

- MAINTENANCE AND SURVEILLANCE

The licensee has maintained the excellent level of performance achieved in the previous SALP cycle. Maintenance work continues to be well coordinated and safely executed; of particular note is the licensee's attention to root cause determination as part of the maintenance process. PSE&G performed well in the planning of and preparation for the Hope Creek refueling outage commenced on March 5, 1994.

In the surveillance area, also, the licensee has continued to perform well; however, personnel error during a surveillance procedure led to the inadvertent isolation of the high pressure coolant injection system in November 1993.

- OPERATIONAL SUPPORT

Licensee performance in the areas of radiological protection and chemistry remains very good. The Radiation Protection Department and the Chemistry Department now report independently to the plant manager. Recent initiatives in the two departments include a clean-booty program for the Hope Creek radiologically controlled area and the use of depleted zinc and hydrogen injection in the feedwater system.

Emergency preparedness inspections have found that program generally well-implemented with very good on-site response to simulated emergencies; an item remains open concerning the licensee practice of not declaring terminated emergencies. Recent safeguard inspections determined the licensee security program to be directed toward public health and safety; however, certain assessment aids have deteriorated to the point where maintenance was no longer properly effective.

- ENGINEERING AND TECHNICAL SUPPORT

Both PSE&G corporate engineering and Hope Creek system engineering continue to provide very good support to the safe operation of Hope Creek. The licensee response to recent generic issues, such as reactor vessel water level instrumentation modifications, core shroud inspections and jet pump hold-down beam replacement, was especially noteworthy.

3. LICENSEE PERFORMANCE STRENGTHS AND WEAKNESSES *

Strengths:

- Operator training and response to events continued to be a notable strength, resulting in a decreased scram rate.

- Implementation of the maintenance program was a strength.

- Management continued to implement measures to improve surveillance testing and to correct identified problems.

- The radiological controls program, including staffing, quality assurance oversight, and ALARA programs were considered state of the art.

Weaknesses:

- Management oversight of firewatch program activities was a weakness common to Hope Creek and Salem.

* Developed from the SALP bullets as well as recent performance observations

4. NRC TEAM INSPECTIONS WITHIN THE LAST YEAR

None

5. PLANNED TEAM INSPECTIONS

None

IV. INSPECTION PROGRAM STATUS

1. STATUS OF INSPECTIONS

The inspection program status is reflected in attached MIPS report #2. The data is current as of the date of the MIP. The MIP indicates that inspection program is on-track with the planned resource allotment; no significant shift in inspection activities is warranted.

2. PROPOSED CHANGES TO MIP

A. DRSS -

B. DRS -

C. DRP

(1)

(2)

3. SIGNIFICANT ALLEGATIONS AND INVESTIGATIONS

- There is only one significant allegation of interest at Hope Creek, and it regards an assertion that performance appraisals are being used as a means of harassment and discrimination for raising issues at the plant. Originally denied followup by the Department of Labor, this case is now in the DOL appeals process.

4. OPEN ITEM STATUS

BACKLOG/No. GREATER THAN 2 YRS

22/1

NOTE: Increased number was due to EDSFI and Surveillance inspection. The item that is currently greater than two years concerns EP training for licensed operators. It is currently under regional management review.

5. OUTSTANDING LICENSING ISSUES

- License Change Request 91-02 - Hope Creek is the lead plant for a BWR owners group initiative to significantly increase the allowable MSIV leakage and delete the MSIV leakage control system. The NRR staff is evaluating the licensee's submittal.

6. LOCAL/STATE/EXTERNAL ISSUES

a. NJ DEPE/BNE

- Now providing input/comments on all PSE&G licensing change requests.
- Provided comments on recent SALP report.
- Interest in resident inspection accompaniment (performed approximately quarterly).

b. Other

- Minimal public interest in SALP Management Meeting.

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SALEM SIT 5/26/95 EXIT MEETING NOTES (Unabridged) 5/24 3PM

Problem Identification and Root Cause Analysis:

The team reviewed the licensees programs for problem identification and root cause analysis to determine if adequate controls were in place to identify plant deficiencies and generate appropriate corrective actions including measures to judge the adequacy and effectiveness of such corrective actions.

Problem Identification Systems

The licensee's current problem identification process is composed of a group of problem reporting systems each governed by specific administrative procedures. These reporting systems are inter-woven into a complex problem identification system which appears to provide an adequate means of capturing pertinent plant deficiencies. The team reviewed approximately 50 problem reports (QA ARs, DEFs, Drs, IRs) to determine if the licensee had adequately implemented the prioritization schemes defined in the administrative procedures. Based on the sample reviewed it appeared that the licensee had adequately prioritized problem reports in accordance with the administrative guidance, with exceptions noted for several incident reports (IRs) discussed separately in this report.

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QA Monthly Reports and QA Audits

Nuclear Safety Review Group

The team discussed the role of the Nuclear Safety Review Group (NSR) composed of the Safety Review Group (SRG) and the Offsite Review Group (ORG) with licensee management and reviewed a sample of recent NSR reports (SRGC 95-014, SRGC 95-018, SRGC 95-004, OSR 95-006, NSAG 94-014). The reports were well documented and in most cases included both evaluations of previously implemented corrective actions and recommended additional long-term corrective actions to recognized problems. The March 1995 SRG Month report (SRGC 95-018) was particularly noteworthy. It provided an assessment of recent operations, maintenance, and engineering activities including specific examples of continued safety tagging concerns, apparent operator work-arounds, poor maintenance practices, and equipment concerns.

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Overall, the NSR's review efforts appeared to be focused on special projects such as follow-ups to incidents or in reaction to special requests for specific information (i.e., recent service water analyses of IRs). The groups have recently started providing certain trend data on a monthly basis including an equipment out of service matrix and a chronological breakdown of IRs annotated with a significance level classification. Additionally the groups track ATS items generated by QA/NSR, open ATS items to the QA/NSR organization, ATS items beyond two years of age, and the number of overdue ATS items. Although these

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trends may provide some useful information to management on workload, it does not appear that the NSR has begun to compile trend data in a systematic manner to independently evaluate or investigate the safety performance indicators as required in the NSR charter, dated April 7, 1995. Further, when queried as to what were the specific safety performance indicators evaluated, the NSR manager was unable to provide a description or representative evaluation of such performance indicators because they had not been developed.

Corrective Action Hit (CAT) Team

The team interviewed members of the CAT team and observed the groups daily activities to determine the effectiveness of the organization. The CAT team's activities can be categorized into three main areas: immediate support to line organizations for the review of incoming IRs, review and development of causal analyses for the backlog of problem reports (IRs, DEFs, DRs). an oversight function to independently evaluate the causal determinations and proposed corrective actions developed by the cognizant line organizations for specific IRs, and to evaluate the effectiveness of those corrective actions.

inconclusive

The team determined that the CAT team is attempting to focus on each of the three main areas. However, due to the volume of requests to assist with the follow-up to current IRs and special assignments (#12 charging pump, safety tagging issues, and the control rod assembly mishandling event), they have not been able to completely review the existing backlog of problem reports (e.g., DR, DEFs, ARs, etc...) and have not been able to dedicate resources to fully address their oversight function.

Trend Analysis of Corrective Action Information

The team reviewed the licensee's processes used to track the effectiveness of corrective actions taken in response to problems identified through the various deficiency reporting systems. The current systems provide for tracking the number of currently open action requests, the line organization responsible for implementing the corrective actions, and the required implementation due dates.

It does not appear that available information to trend/analyze all outstanding action requests or the effectiveness of completed corrective actions associated with a system or component are being utilized effectively. The system engineering log books provide raw IR data and certain component performance trends for use in developing corrective maintenance plans. The team discussed the methods which are used to evaluate system performance with the Service Water System Manager. The manager mentioned that the current MMIS database is difficult to use for generating evaluation reports because it is not set-up to provide a direct method for trending problem reports or corrective actions taken. As a result ad-hoc reports can be generated by downloading MMIS data into other applications but that is limited to a few engineers with expertise in performing such downloads. Additionally the manager receives periodic reports from the Reliability Assurance Group if system components were requiring repeat rework (e.g., 10-15 repeat work

orders). The system managers also receive copies of IRs related to their systems from their supervisor attending the 8:30 meeting. Although there appears to be a significant amount of information available to analyze specific systems, the current process does not specify what analyses should be performed by the system managers. When the team asked the Service Water System Manager what analyses were produced as a result of the information contained in the IRs and log book for his system, he was unable to specify any.

Incident Reports

Significance level determinations

The team reviewed a sample of recent IRs and observed the daily 8:30AM engineering meeting in order to judge the effectiveness of the process used to determine IR significance levels. Significance levels are generated through a consensus of the engineering supervisors attending the daily meeting. Each IR is briefly discussed and dispositioned by determining the line organization responsible for the review and assigning a significance level in accordance with the definitions provided in NAP-06, "Incident Report/Reportable Event Program," Revision 8, dated 4/7/95. These definitions are:

Although the observed consensus approach appeared to be generally consistent, the apparent lack of specific criteria for what is safety significant, potentially safety significant, and for minimal impact on safety significance may have contributed to some weaknesses noted with the classification system. The team found several examples of IRs (IRs 95-401, 95-551, 95-507) categorized at significance level 2 which appeared to be consistent with the significance level 1 definition of the current NAP-06 guidance (e.g., "safety significant or potentially safety significant or repetitive failures"). Additionally, the CAT team had identified a number of IRs which based on their evaluation were reclassified from significance level 3 to level 2. These examples were discussed with the CAT team and QA/NSR management who agreed that the descriptions in the current NAP-06 should be revised to be more explicit in terms of what is safety significant, potentially safety significant, and have minimal impact on safety significance. Based on these observations, it appears that there have been some misapplications of NAP-06 guidance regarding determination of IR significance levels.

Workload Assessment

The revised NAP-06 guidance regarding the dispositioning of incident reports was effective on April 12, 1995. The revision created a graded approach to analysis of IRs based on a tri-level system described in Section XX of this report.

Given this data, for the period from 4/12/95 to the 5/11/95 the corrective action program has generated approximately 1625 person/hours of effort to review IRs and determine causal factors for each. At present it appears that the workload associated with reviewing IRs is growing, which, if not addressed, will interfere with the licensee's ability to determine and assess the significance of problems and root

causes in a timely manner.

Root Cause

The team reviewed a sample of recently completed root cause analyses (IRs; 95-262, 95-308, 95-302, 95-294, 95-297, 95-301, 95-287, 95-203, 94-384, 95-005, 94-528, 95-012, 95-015, 95-052, 95-062, 95-074, 95-335). The sample contained IRs which represented all three significance levels per NAP-06.

While the team did not find specific faults with the final root cause determinations, there were apparent weaknesses with the documentation to support the evaluations. These weaknesses included wide variability in the level of detail between the analyses and lack of information to support responses on the root cause evaluation forms. These weaknesses could diminish the usefulness of the corrective action program by limiting useful comparative analyses between incident reports.

The ability to search for repeat occurrences or similar conditions across the database of IRs, and the ability to reconstruct the incident during subsequent evaluations could be hindered by this lack of detail.

Programmatic issues identified by the team which appeared to contribute to these weaknesses were: (1) lack of root cause training for all individuals given responsibility for performing IR analyses; and (2) lack of explicit written expectations for the review effort in NAP-06.

WORK CONTROL

Scope

The team assessed the effectiveness of the licensee's processes for prioritizing, planning, scheduling, and controlling work on plant equipment. The team observed daily activities associated with the work control process, including schedule review and status meetings and work control center (WCC) activities. The team also reviewed procedures and other written guidance, schedules, and work orders (WOs) and held discussions with personnel involved in all aspects of the work control process.

Prioritization of Work

When deficient conditions were identified, the incoming action requests (ARs) were reviewed promptly to determine the priority and appropriate action to address the condition.

The team determined that the established criteria for prioritization of work was adhered to consistently.

The team was concerned that failure to revise the priority of a work item could result in failure to schedule the work at the appropriate time.

Operations defined the daily priorities for the station, but these priorities were not always communicated clearly and effectively

throughout the licensee organization.

During the second week of the inspection, operations management attempted to provide some consistency in communication of priorities between the various daily meetings by defining critical evolutions and ops priorities for each unit and presenting these issues verbally at the 8:00 a.m, 8:30 a.m., and 1:00 p.m. meetings. The effectiveness of this effort was limited by the verbal presentation, the inconsistencies in the written information provided at the meetings, and the timing of the presentation.

In addition to the inconsistencies between the various meetings, communications related to priority issues were often hindered when personnel with key status information were not present at the status meetings or were not knowledgeable of the status of the issue. In some cases, the individual running the meeting did not appear to have a clear understanding of the priority issues. The team also noted a number of instances in which personnel from different groups had a different understanding of the status of a priority issue. This confusion was rarely resolved at the meetings.

Poor communications during meetings 7 examples

The team identified the following examples of poor communication on priority issues at the daily meetings:

- At the 8:30 meeting on May 4, 1995, the radiation monitoring system (RMS) central processing unit (CPU) was identified as the number one operational concern, but representatives at the meeting did not know the status of the work.

- At the 8:30 a.m. meeting on May 8, 1995, the unit 2 control rods in manual was identified as a daily ops priority. This issue was not presented as an ops priority at the 8:00 a.m. managers' meeting on the same day.

- On May 8, 1995, 11 reactor coolant pump (RCP) seal leakoff was trending up and the issue was verbally presented at the 8AM and 8:30AM meetings as one of the daily operations priorities for unit 1, but the issue was not listed on the daily status sheet.

- On May 9, 1995, the 11 RCP seal leakoff trend was again presented as a daily ops priority and was listed as an operational concern on the daily status sheet. However, there was confusion during the 8:30 a.m. meeting concerning whether information known by engineering, that the other three RCP seal leakoffs were also trending up, had been communicated to operations.

- On May 9, 1995, only one of the operational concerns listed on the unit 1 daily status sheet was listed as an ops priority on the POD. None of the daily ops priorities provided verbally at the 8AM meeting were listed on the operations priority list on the POD.

- At the 8:30 meeting on May 4, 1995, there was confusion concerning the status of the operability determination for the unit 1 axial

flux differential (AFD) monitor which was listed as an operational concern on the daily status sheet. The holdup on the issue was identified on the daily status sheet as the design change package (DCP), but some individuals at the meeting believed that the holdup was due to a parts problem.

The AFD monitor was added to the ops priority list in the POD on May 5, 1995, but was deleted from the list of operational concerns on May 8 (over the weekend). At the 8:30 a.m. meeting on May 8, no one knew if the AFD monitor had been repaired or if work was planned for that day.

The team also noted weaknesses in the coordination of activities associated with priority issues. Even when jobs were clearly identified as high priority, problems with communications and work quality often hindered accomplishment of the work. The following example of how work on the unit 2 28V DC battery chargers progressed illustrates the types of problems observed by the team.

At 4:49 p.m. on May 1, 1995, a seven day Technical Specification action statement (TSAS) was entered for the 2A1 28V DC battery charger which was declared inoperable due to an installed ground detection system that was not per system design. The battery charger issue was first identified as a priority issue at the daily meetings on May 2, 1995. On May 3, operations was waiting for a work package to remove the ground detection system and the DCP needed to be written.

On the morning of May 4, operations was not satisfied with the operability determination provided by engineering and the DCP was returned for revision. Later in the day, the general manager (GM) identified that the post modification test was inadequate and the DCP was again returned to engineering for revision. The DCP was finally approved by the GM at 9:30 p.m. on May 4.

Maintenance received the work package at 2:00 a.m. on May 5, but did not commence work because the procedure required contacting installation and test personnel and none of the maintenance personnel knew how to contact the appropriate personnel. They tried to resolve the problem until 4:00 a.m. then decided to wait until day-shift.

On day-shift on May 5, the on-shift WCS in the WCC was told that 28V DC battery charger work (on both units) was the highest priority work, but he was not provided with any details on the nature or plan for the work. Tagging requests had been prepared in advance in the safety tagging preparation office (STPO) and delivered to the WCC, but this was not known by anyone working in WCC at the time. A plan for the work had been established, but was not communicated to the WCS in the night order book (NOB) or through turnover.

The electrical maintenance supervisor brought two WOs to the WCC and didn't clearly communicate what he needed to the WCS. One of

the WOs was for a battery charger that was in service (2A1) at the time which caused the WCS to question the work. The confusion caused by the maintenance supervisor's failure to communicate and failure to inform the WCS of the plan for the work resulted in delay in authorization of 28V DC battery charger work (on 2A2) and impacted other high priority jobs on both units including tagging of the 12 steam generator feed pump (SGFP).

Scheduling of Work

X The team determined that the process used to schedule non-outage work items was logical and well managed to minimize risk to plant operations.

Work items were scheduled based on priority, risk assessment, and opportunity within the established system window and work week schedules.

Limitation of work within a week to one bus or channel minimized the potential of inter-system operational conflicts between scheduled work activities.

X Net safety gain (NSG) assessments were performed to assess the risk associated with performing preventive and corrective maintenance on all risk significant systems.

NSGs were required for both planned and unplanned maintenance activities. The only exception to the requirement for a NSG was if a deficient condition requiring unplanned corrective maintenance rendered the affected equipment inoperable and a TSAS had already been entered.

The team determined that non-outage work schedules received multiple multi-disciplined reviews prior to finalization of the schedule two weeks in advance of the scheduled work week.

Locking in the schedules two weeks in advance allowed time for thorough review of the planned work activities and facilitated preparation of tagging requests and work packages well in advance of work performance.

X The team noted that the licensee performed thorough, detailed risk assessment and planning for major work activities.

X [WASN'T THIS JOB POORLY HANDLED?] During the inspection, the licensee was considering a power reduction to replace a card in the electric hydraulic control (EHC) system. They performed a risk assessment and determined that the risk associated with reducing power and performing the maintenance outweighed the risk associated with continued operation with the potentially defective component and deferred the maintenance. Also during the inspection, the licensee reduced power in unit 1 to perform repairs on the SGFP governors. They performed a detailed NSG assessment, identified compensatory measures to reduce the risk due to unavailability of the SGFPs, and developed a detailed schedule for all the work activities including taking the pumps out of service and performing post maintenance testing.

The team noted that repetitive tasks (surveillance tests and preventive maintenance activities) were not always scheduled to be performed before

the due date for the task. Why isn't this OK?

the team identified a large number of PMs and a few STs that were scheduled to be performed in the grace period between the task due date and the overdue date.

tests were scheduled to be performed late in the grace period only a day or two prior to the overdue date. If problems had been encountered during performance of the tests, the Technical Specification (TS) surveillance intervals could have been exceeded.

The team also noted that PM deferral requests (PMDRs) were not always initiated in a timely manner. Licensee management expectation was that PMDRs would be initiated as soon as it was identified that a PM could not be scheduled for completion prior to the overdue date so that the PMDR could be resolved prior to the overdue date.

The team identified several PMs that were scheduled to be performed after the overdue date that did not have open PMDRs.

Schedule Adherence

The licensee recently implemented actions intended to reduce the amount of unplanned emergent work being performed, by defining controls on "Sponsored Work". Any work added during the actual work week had to be approved by the GM. The team determined that licensee personnel were adhering to the intent of the sponsored work policy,

No training on sponsored work?

but that the policy was not clearly defined and was not effectively communicated to the working level of the organization (i.e., the on shift WCSs and first line supervisors).

The definition of what work required sponsorship was not clearly understood throughout the organization. Maintenance and operations personnel both indicated confusion on whether work items that were added to a previously scheduled job required sponsorship.

All of the WCSs that were questioned by the team understood the expectation to strictly adhere to the work schedule, but none of them were familiar with the term "sponsored work."

one WCS indicated that he would consider release of work on equipment that was already out of service or had no impact on operations without consulting the SNSS.

The team was concerned that, because sponsorship was not a formal process and that the policy was not well understood at the working level of the organization, the process could be unintentionally or inadvertently bypassed through the scheduling process. The schedules in the POD were discussed at the 6:30 a.m. supervisors meeting, but there was no line by line review of the schedule that would identify work items that had been added to the schedule without sponsorship. The team identified an item that was added to the schedule for May 5 which inadvertently bypassed the sponsorship process. (WHAT ITEM?)

Work Authorization

The licensee had recently established a safety tagging preparation office (STPO) to review work packages and prepare tagging requests in advance.

The team noted that the work authorization process was in a state of flux and that the process was not always implemented consistently.

The team observed several instances in which the combination of lack of clear understanding of responsibilities, inconsistent implementation of the process, and poor communications led to confusion in the WCC.

the effectiveness of the change was hindered because the changes to the work authorization process hadn't been clearly defined in writing and hadn't been clearly communicated to on-shift WCSs and first line maintenance supervisors.

No specific training was provided to the on-shift WCSs on the function of the STPO and the changes in the division of responsibilities for work package review and work authorization.

Some of the WCSs on-shift during the inspection hadn't been in the WCC for several months.

in some cases the STPO pre-approved WOs for emergent work, and in other cases the packages were reviewed and the tagging requests were prepared in the WCC. These differences often led to confusion on responsibilities and status of work packages.

The work had been previously scheduled for the following week, but had been added to the schedule for May 5 and sponsored by the GM. The STPO had pre-approved the WO and the required tags had already been added to the tagging request, but this was not communicated to the maintenance supervisor or the WCS in the WCC.

Quality of Work Packages

The licensee used maintenance feedback sheets in order to improve the content of work packages and to identify and correct the reasons for lost time during maintenance work.

for Unit 2, 26% of the feedback sheets identified scheduling conflicts or issues and 9% identified that incorrect man-hours were specified. The maintenance managers shared this summary information with their staffs at their routine all hands meetings.

records of the feedback sheets and applicable corrective actions were not being consistently maintained by the maintenance organization to ensure that all feedback is acted upon and to enable valid trending of the information.

Licensee representatives indicated that it was a known problem that PM work packages often did not meet quality expectations because, when the packages were originally prepared, standards for work planning were lower. At the time of the inspection, the planning department was relying on the feedback process to improve the work packages for repetitive tasks rather than correction during the planning process.

The team observed that problems in work packages / planning were still found during performance of the job in spite of the improvements in the planning and review processes. For example,

1B the planning process didn't identify that corrective maintenance on the 1? diesel generator required running the other diesels. The team observed that problems in work packages were still found during performance of the job in spite of the improvments in planning and review processes. For example, the planning process identified work to be performed on the 1B emergency diesel generator (EDG) as corrective maintenance, yet failed to plan for or schedule the Technical Specification-required surveillence running of the other two Unit 1 EDGs. It was only when complications arose during the performance of the work that operators deemed the work corrective maintenance and ran the other Unit 1 EDGs. When the operators reached that conclusion, the other two EDGs were operated concurrently due to time constraints in the original Technical Specification allowed outage time. Running the two EDGs concurrently was contrary to the guidelines of NRC Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants." The team concluded that the eventual problems realized concerning the operation of the two other EDGs during maintenance on the 1B EDG could have been avoided had the original corrective maintenance work package included the proper scheduling of the required surveillance runs.

Although, operations had more time to review work in advance, they did not review the entire work package. Only the WO cover page and summary sheet were provided to operations for review. The remainder of the work package was only reviewed by the group responsible for performing the work.

troubleshooting procedures were incorrectly used in some work packages where a regular procedure should have been used. **(Pete to provide details on inappropriate use of troubleshooting procedures)**

Problems with bill of materials may warrant a broader review to correct problems with the BOMs than what is being done currently. **(Pete to provide details)**

OPERATIONS

OPERABILITY DETERMINATIONS FOR DEGRADED COMPONENTS AND SYSTEMS

1994? Last summer, Salem Operations implemented a process by which operating crew ~~shift super~~vision would make operability determinations (ODs) for degraded plant components or systems. This process was implemented via an entry in the

no training on ODs.

operating crew Night Order Book and an accompanying flowchart to direct the operators while making these determinations.

The team determined through the review of the most recent ODs that the licensee has not been making operability determinations with the proper perspective to safety and regulatory requirements. The licensee has used equipment redundancy, the lack of Technical Specification or UFSAR documentation, the lack of an effect on the reactor protection system, and fail-safe positioning to improperly justify operability.

Through operator interviews and review of previously accepted ODs, however, the team determined that senior licensed operators and Salem system engineering had demonstrated weaknesses in the operability determinations area, since a large number of ODs had been prepared and accepted with flawed bases. Examples of these inappropriate bases for ODs prepared and accepted in the past two months included:

Very poor operability decisions 8 examples

- a 125vdc battery OD for cell seal degradation used a 10CFR50.59 review that cited for its basis the fact that the battery cell seal was not specifically mentioned in the Salem UFSAR, and therefore a safety evaluation was not required;

- a No. 22 residual heat removal (RHR) room cooler OD for the use of a non-qualified fan motor cited the fact that there was a redundant RHR train available, therefore the use of the motor was acceptable;

- an erratically-performing steam flow channel OD cited that maintenance had done all they could to repair the channel, therefore it was operable, but advised operators to be conservative and use an other channel;

- an RCS sampling valve OD for a faulty supply breaker cited the fact that the valves failed in the safe closed position, and concluded the breaker and valves were operable without assessing the ability of the components to perform their design function;

- an RM 23 and RM 80 radiation monitor channels OD acknowledged that a design change package had inappropriately removed the annunciator reflash capability and that the Technical Specification intention of the channels was not being met, yet concluded the channels should be considered operable until an alarm is received, only making the other channels inoperable at that time;

- a reactor coolant loop flow channel that had shown erratic behavior twice within a week in January 1995 did not have an OD performed until April 1995, when the channel was declared operable after a contractor was not able to repeat the behavior;

- an emergency diesel generator OD written to address fuses that were identified as being different than those specified justified operability via a problem report which discussed functionality without considering the basis for the apparent design change

(i.e., with no 10CFR50.59 review); and

- a feedwater flow control channel OD that was written after the channel exhibited improper transition from automatic to manual control justified operability based on the fact that feedwater flow was not part of the reactor protection system and that the reactor protection system was operating satisfactorily.

All of the above ODs had been prepared and accepted in the two months preceding the inspection.

While the team was on site Operations management began to provide closer oversight of the OD process. As a result, operating crew shift supervisors improved their level of knowledge concerning operability and became more discerning in their acceptance of OD input. The team observed, however, continuing cases of system engineering supplying justifications with improper bases.

Examples of the improper operability bases proposed by system engineering that shift supervision rejected while the team was on site included:

Bad ODs by System Engr. 3 examples

- after a discrepancy in the ground detection circuit of the 2A1 28vdc battery charger and 2A vital 28vdc bus was identified, system engineering supplied a memo to Operations attempting to justify system operability based on the availability of the redundant vital bus;

- after the Unit 1 containment personnel access airlock failed a leakage test for the second time within a week, system engineering supplied a memo to Operations which concluded the cause of the failures was dirt on the airlock seal and the airlock was not degraded. When Operations rejected the memo and its assumption of root cause, further investigation revealed that the airlock had, in fact, a mechanically degraded seal; and

- after a discrepancy in the configuration of an air supply valve to the auxiliary feedwater system was identified in an incident report, system engineering supplied a memo to Operations justifying system operability based on the availability of a redundant air supply.

The team identified several examples where the licensee had not properly evaluated the operability of degraded equipment and systems. This observation is similar to the conclusions reached by a NRC team which conducted a performance assessment of Salem in July-August 1994. The team concluded that the large volume of ODs, the inconsistent method with which they have been prepared, and the examples of improper justification of operability have resulted in the operation of the Salem units in a condition other than that designed without the proper and required review by the licensee staff.

CONFIGURATION CONTROL

Configuration control and knowledge of plant construction has been a historical problem at Salem.

Partially in order to address the problem, Salem Operations created a new tagging office in early April 1995.

Due to the large number of configuration control discrepancies, the tagging office has required equipment operators to walk-down work order packages in the field to verify the accuracy of P&IDs and work package boundaries for tagging orders.

The team reviewed all of the incident reports written in the month preceding the inspection and identified over 50 examples which described deficiencies in the areas of P&ID accuracy, component labeling and TRIS accuracy.

an incident report in early April 1995 which documented a backlog of approximately 2000 items to be entered into TRIS and that none of those items had been reviewed or prioritized for safety significance.

The team also observed that, while the new tagging office was making progress in the area of tagging releases and identifying configuration discrepancies, tagging errors continued to occur at the plant. Four examples which occurred while the team was on site included:

- a service water system sump pump breaker was found in the closed position, despite the presence of a shift supervisor administrative tag that required shift supervisor permission to close the breaker, in order to prevent an unmonitored chemical release to the river;

- a work order for work on the No. 13 service water pump failed to include the tagout of the pump motor thermocouple, resulting in a potential equipment and personnel hazard;

- an operator walkdown of a tagging request identified that the incorrect "B" building air cooled condenser was listed on the tagging request, resulting in the determination that both "B" building condensers were identically labeled; and

- the tagging request for the work on the No. 12 steam generator feed pump governor replacement contained an improper valve position on the TRIS lineup sheet.

At the time of the inspection, NED had only identified, and the site VP/CNO included, the configuration control issue as an IMPACT Plan item, with a plan for corrective action due by the end of June 1995.

In summary, the team observed that configuration control and, to a lesser extent, safety tagging errors continue to occur at Salem. The team determined that the breadth and scope of the problem constituted a burden on the Salem operators' effort to safely operate the Salem units. Licensee management has not reacted in a proper manner to the evidence of the problem's existence.

OPERATIONS WORK AROUNDS

The concept of Salem operators implementing work arounds to compensate for equipment or systems that were not performing as designed is also an historical problem. The problem was highlighted during the grass intrusion event which resulted in a reactor trip and multiple safety injections last April. Due to long-standing problems in the performance of the systems, operators were operating the plant with the reactor control rods in manual control and, as a result of controller reset wind-up problems, manual action had to be taken for the proper operation of the steam generator atmospheric relief valves. Complications in the operation of those two systems directly contributed to the April 1994 event. As a followup to that event, the licensee consolidated a list of operator work arounds in August 1994. In September 1994, the list of work arounds was frozen at 80 problem statements, with problem initiators and owners identifed for problem resolution.

During this inspection, the team reviewed the current work around list and determined that over 70 items remained as work arounds from the list that was frozen in September 1994. The licensee was tracking progress on the remaining open work arounds and was in the process of developing a system to track and initiate corrective actions for work arounds within the routine work control process.

The team observed that additional work arounds existed in the plant at the time of inspection, yet were not being tracked as such due to the work around list being frozen last year. Examples included: the operators dealing with numerous spurious self-test failures on the Unit 1 safeguards equipment cabinet; the Unit 2 rod control being maintained in manual due to rods inadverently stepping as a result of a problem in the automatic control temperature comparator; and the operators continuing to deal with failures in the Salem radiation monitoring system. None of these examples was on the current work around list.

While the team was on site, the licensee claimed to have reduced the number of open work around items to 38. This new number was based on the licensee revising the definition of a work around; the new definition was derived as a result of the NRC performance assessment of Salem conducted in July-August 1994, and considered as an operator work around any "non-routine actions performed by the operating crews due to equipment not functioning as designed." With the new definition, the number of open work arounds was reduced approximately in half. The licensee designated the remainder of the former work around items as plant betterment issues and intended to track the progress of their closure separately from the work around items.

In an area related to work arounds, the team reviewed the use of shift supervisor administrative safety tags. These tags are authorized by operating crew shift supervisors to control the use of certain equipment in the plant in that shift suprvisor permission is required prior to

operation of any component with one of these tags attached. An example of this type of usage is cited in Section X.2, above, where a shift supervisor admin tag had been hung on the breaker for a service water sump pump to control operation of the sump pump to prevent inadvertent use and an uncontrolled environmental discharge from the service water sump. In the above cited case, the instructions of the tag had not been complied with, and the pump breaker was incorrectly left in the closed position. The team determined that approximately 150 tagging orders were in effect for the use of these type of tags at the time of the inspection. The team concluded that this use of safety tags was not directly provided for in the controlling procedure for the use of safety tags, NC.NA-AP.ZZ-0015(Q),"Safety Tagging Program," and that the use of these tags constituted a form of work around in that the tags were used to accomplish a purpose for which more appropriate means existed. The team further concluded that the use of shift supervisor admin tags had the potential of desensitizing the plant staff to the the operation of equipment with safety tags attached. Operations management informed the team that the licensee had plans to reduce the use of these tags and implement other means such as procedures and operator aids in their place.

TS 6.8.1 ? Violation ? AP 15 ?

In summary, the team determined that a large number of operator work arounds still exist at Salem and place an additional burden on the safe operation of the plant. The licensee has developed or is developing additional ways of addressing the issue, yet by the licensee's own performance indicators, the average age of work arounds at Salem was 21.3 months as of April 27, 1995. The team concluded that additional management attention is warranted in this area in order to eliminate the current work arounds and to resolve work arounds which may later develop in a more timely fashion.

Management Oversight

During the period April 26 through May 11, 1995, the team assessed the effectiveness of management oversight and the performance indicators used by management to measure current Salem performance. This assessment was based upon observation of the daily 8:00 am station managers' meeting, work activities, discussions and interviews with management and other licensee personnel.

NRB

Safety Perspective

During the inspection, the team noted that management demonstrated a good safety perspective on a number of occasions. For example, at the management team meeting on April 27, 1995, a tagging problem, that had occurred the previous day, involving a safety tag on a service water sump pump breaker that had been violated was responded to quickly by the General Manager and set in motion a series of steps to sensitize station personnel to the importance of complying with the safety tagging system. Also, at the managers' meeting on

May 11, 1995, several examples of good safety perspective were noted. For example, regarding debris found in the #2 station air compressor cooler, the operations manager cautioned the other managers to not prematurely focus on the debris as being the root cause of the elevated temperatures seen in the air compressor, without considering all other possibilities.

However, notwithstanding the noted improvement seen at the end of the inspection; overall, licensee management did not exhibit a strong safety perspective. The team observed several instances in which management "missed" the opportunity to demonstrate a strong safety perspective at the managers' meeting. Several examples are discussed below:

- On April 27, 1995, in response to discussions about recent problems with the Service Water System involving recent corrective maintenance on such as inoperable traveling screens, incorrect bolting, water in lube oil and inoperable strainers, the Station Manager requested that the system engineer brief the management team at the following days 8 AM meeting. On April 28, the system engineer told the managers that he did not believe that the condition of the Service Water system had degraded. He stated that the increase in degraded conditions was the result of increased station emphasis on documenting, investigating and correcting degraded conditions. The management team did not question the engineers conclusion, or ask any questions about what the history of corrective maintenance was for the system or whether the evaluation of this history supported the conclusion that the system was not degrading. Followup questioning of the engineer by the NRC resident staff revealed that the engineer had not made comparisons of equiment history records to support the conclusion that the system had not degraded.

- On May 2, 1995, the Operations Manager mentioned that a maintenance worker had begun to do work to alter the configuration of a 28 volt battery charger using a work order, without a design change package (DCP). The unacceptability of performing a design change on safety related equipment without the required reviews and documentation of a DCP was not raised as an issue at the meeting and no one was designated to provide followup to the managers at the next day's meeting.

- On May 8, 1995, the Operations Manager's representative discussed an incident report regarding the containment airlock door leakage test failure. It was the second time in a week that the test had failed. It was mentioned that dirt had been found on the seal both times. A manager questioned the operability of the containment air lock door and the root cause for the door failing it's leakage test twice within one week. The manager was demonstrating a good questioning attitude. However, he was quickly stifled by other managers, and he backed away from his concerns. The other managers lacked a questioning attitude and accepted the easy answer of dirt as the cause. Later in the meeting, operability of the door and apparent lack of an identified root cause was questioned, and one manager inferred that the identification of dirt on the airlock door seal constituted an adequate root cause analysis. After further evaluation and testing, the licensee determined that the airlock door had failed the leakage test because the seal was degraded.

individual did not understand why saying that the margin of safety is not reduced because the diesel generator air start system and its components are not the subject of any TS or TS basis was an inappropriate answer.

Management Oversight Group

Following the April 7, 1994 event, the licensee established a Management Oversight Group (MOG) to provide additional, independent management oversight of plant operations.

Overall the team found that the MOG effort was a good initiative. They identified some good findings and provided real time observation as expected by the General Manager. However, they failed to identify the significant team finding of inadequate operability determination bases discussed in section xx of this report.

Management Oversight of Priority Issues

At the managers' meetings, the team noted that the managers were not always knowledgeable of the specifics for the ongoing priority issues, both safety and non safety related. They were unable to answer questions from the General Manager involving schedule issues, when degraded safety equipment had entered its technical specification action statement, and the status of parts needed to return degraded equipment to service. They also were not knowledgeable in some cases of work delays and the reasons for those delays. For example,

> on May 5, the managers did not know the 1B1 battery charger LCO start and stop times, and therefore that they were in day 3 of a 7 day LCO;
>
> and on May 10, the managers did not know the status of parts for the 21 MSR drain tank level indication which had been a priority issue for over 24 hours and was the reason for a 10% power reduction.
>
> Also, on May 5, the managers did not understand the reasons for delays in the 28 volt battery charger work, which had been a priority job for at least three days.

As the inspection progressed, the General Manager demonstrated that he knew more about the specifics and status of priority jobs than the managers. For example:

- On May 5, the General Manager described activities associated with the 28 volt battery chargers which showed that he had followed aspects of the job and had visited the work site. Upon questioning by him, the managers were unable to provide status information or reasons for delays. In addition, prior to approving the battery charger DCP on May 4, the General Manager identified weaknesses in the DCP post modification testing of the battery chargers.

- On May 10, the General Manager pointed out and took issue with what appeared to be communication problems related to the previous days priority jobs.

Performance Indicators

The licensee had identified seven performance indicators in their response to the Notice of Violation and Civil Penalty associated with the April 7, 1994 event. These were Event Free Operations, Unplanned Automatic Scrams, Personnel Performance Incident Reports, Repeat Equipment Problems, Corrective Maintenance Backlog, Preventive Maintenance Overdue, and Repeat Cause Incident Reports. The licensee stated that these performance indicators would be used to determine the effectiveness of the actions they had identified for improving performance. The licensee had also identified about 18 other performance indicators used to monitor performance. These included Safety System Unavailability, Control Room Indicators Out of Service, LERs, and NRC Violations. All of these indicators are published quarterly and distributed to the department managers and above.

The team found several weaknesses with the performance indicators being used by licensee management to measure Salem performance. In some cases the indicators either were not predictive and/or had too high of a threshold for inclusion of data. For example:

- The indicator for Preventive Maintenance Overdue included the number of preventive maintenance tasks which were open and past their overdue date. A predictive indicator would include preventive maintenance tasks past their due date instead of overdue.

- For the indicators designed to track human performance, Personnel Performance Incident Reports and Repeat Cause Incident Reports, the indicators were not completely based on root cause investigations but instead on preliminary data. As a result, the actual number of personnel performance or repeat events could be substantially different from those in the performance indicator. (A Safety Review Group (SRG) review of 29 incident reports with completed root cause investigations, found that 37% of those attributed initially to equipment problems were actually human performance or management problems.) Also, for these indicators, the licensee only included incident reports that reached the threshold for reporting per 50.72 and 50.73, or the threshold for being designated significant by the NRC, Noteworthy or Significant by INPO, or the threshold for resulting in an internal Significant Event Response Team (SERT). The causal factors for incident reports that do not meet the threshold criteria are not included in this performance indicator. Per the SRG review, industry experience has shown that the causal factors are the same for both nonconsequential and consequential incidents. As a result, these indicators have not been used in a way that identifie trends in-turn may lead to more significant problems, if not corrected.

- For Repeat Equipment Problems, the original list of monitored equipment was limited to the NPRDS listing which did not cover some of the specific equipment that has adversely affected the operation of the stations, such as the service water strainers. In approximately the last two years the valves had been out of service eight times for corrective maintenance, but they were not included in this indicator. In addition, problems that resulted in degraded equipment but did not make the equipment inoperable were not reported to NPRDS, such as the problems associated with feedwater regulating valve 11BF19. This valve was worked on five times in the last 18 months for erratic operation or

loose parts, but no NPRDS reports were made because the valve was not considered inoperable.

The team found that in many cases licensee management had available to them the data which could have been used to provide more meaningful measures of Salem performance. [DETAILS]

However, in most cases [DETAILS] no licensee action was taken to further evaluate these trends. In the area of configuration control, an extensive evaluation of the trend was conducted in 1994, however, the licensee did not take substantive action to reverse the trend **(Pete, need to tie this to Steve's write up on this issue)**.

The licensee has taken steps to design more meaningful and informative performance indicators. The Safety Review Group completed a review to analyze and validate several of the performance indicators in early April 1995 and provided the results to the General Manager. The indicators for April 1995, to be published in May, were changed to reflect some of the findings of the SRG review. For example, the Repeat Equipment Problem indicator was changed to Recurring CM Work Orders to better reflect the condition of equipment at Salem which could adversely affect the operation of the stations. For Preventive Maintenance Overdue, the indicator was changed to include preventive maintenance tasks which were not completed by their overdue date and were deferred by the system engineer. In the past, these preventive maintenance tasks were not included in the indicator which provided a more positive indication of the health of the preventive maintenance program.

During the period April and May 1995, Operations management developed new indicators for mispositioning events, procedure events, tagging events, and unplanned technical specification action statement entries. The first three of these indicators showed an increasing (negative) trend since January 1995. But at the end of this inspection, the licensee had not yet evaluated these trends to determine what actions to take.

Indicators not effectively followed up

In addition to the IR trend on P&ID problems discussed in the configuration control area, the team noted that the IR trend on procedure adherence problems had been showing an increasing trend of occurrences for the past several months; however, management had not taken action to date to assess the significance of this trend.

Conclusions

The team identified several weaknesses in the effectiveness of management oversight and the performance indicators used by management to measure current Salem performance. Management "missed" the opportunity to demonstrate a strong safety perspective at the station manager's meeting. Also, at the meeting, the managers were not always knowledgeable of the specifics for the ongoing priority issues, both safety and non safety related. Although the SORC identified and properly dispositioned several issues at the routine SORC meeting, the identification of these weaknesses came solely from the

Operations Manager, as opposed to the SORC as a whole. The other SORC members contributed minimally to the critical aspects of the conversation. Overall, the MOG effort was a good initiative. However, the MOG failed to identify the significant team finding of inadequate operability determination bases discussed in section xx of this report. Also. the performance indicators being used by licensee management to measure Salem performance were weak in that some indicators either were not predictive and/or had too high of a threshold for inclusion of data. In many cases, licensee management had available to them the data which could have been used to provide more meaningful measures of Salem performance, however, they were not routinely using this data to identify and evaluate trends, and measure performance. And for those instances when a trend was identified, the licensee did not take substantive action to reverse the trend in a timely manner.

Pete - NRB

II. PLANT PERFORMANCE DATA

1. **CURRENT OPERATING STATUS** (for period 1/29/95 to 3/11/95)

Unit 1 began the period operating at 100% power. On February 3, the licensee initiated a unit shutdown to comply with plant Technical Specifications. During implementation of a DCP to correct a problem with a solid state protection system (SSPS) power feed, a redundant power supply tripped. The licensee was unable to fully restore SSPS to operability within the technical specification limiting condition for operation action statement allowed outage time. On February 4, the licensee entered Mode 5 (Cold Shutdown) to address SSPS concerns. On February 15, operators entered Mode 4 (Hot Shutdown). The licensee maintained the unit in Mode 4 while resolving problems encountered with main steam atmospheric relief valves (MS-10s). On February 27, operators commenced a reactor startup. On March 2, operators increased power to 48%. On March 3, operators reduced power to 28% to make a bioshield entry to adjust RCP oil levels. On March 8, operators increased power to 100% and maintained the unit there for the remainder of the period.

Unit 2 began the period in Mode 3 (Hot Standby). On February 1, operators commenced and completed a reactor startup. On February 3, operators commenced a Technical Specification required shutdown from 1% power, following removal of NRC Enforcement Discretion due to potential common mode failure of SSPS power supplies. The licensee placed the unit in Mode 5, completed troubleshooting and repairs to SSPS, and commenced a plant startup. On February 11, operators took the reactor critical and commenced a power increase. On February 19, the licensee initiated a shutdown from 47% power to remove the no. 21 Reactor Coolant Pump from service in response to low seal water leakoff flow. The licensee entered Mode 5, replaced the no. 1 seal on no. 21 RCP, and commenced a plant startup. On March 8, operators achieved reactor criticality and commenced power escalation. The unit completed the period at 90% power.

2. **RECENT SIGNIFICANT OPERATING EVENTS AND IDENTIFIED SAFETY CONCERNS**

a. <u>Significant Events (since April 1994)</u>

- On February 3, 1995, a unit 1 main steam atmospheric relief (13MS10) valve would not open in response to manipulation of controls. On February 10, 1995, 22MS10 would not respond in automatic to steam pressure above the pressure setpoint. These problems were the latest in a long history of events with MS10 (and Hagan module) performance problems (including April 7, 1994 event). The licensee did not initiate a thorough root cause until prompted by the residents and Regional management. A thorough root cause, performed by a multi-disciplinary team, concluded that contributing factors included inadequate maintenance, vendor

refurbishment, design, control of parts, and operator understanding of design contributed to the performance problems. (IR 95-02, not yet issued.)

- During late January 1995, Salem sought and was granted a Notice of Enforcement Discretion to address design deficiencies with the Solid State Protection System. Electrical components (e.g. limit switches and pressure sensors) associated with main steam, turbine controls, and feedwater were susceptible to rendering all or most of SSPS inoperable based on a single high energy line break. When unexpected power supply trips occurred during the modifications, Region I withdrew enforcement discretion.

- On January 11, 1995, with Salem Unit 2 in Mode 4, the no. 23 RCP seal water return valve for the no. 1 seal closed, isolating seal flow. The licensee determined that the pressure diaphragm of the ASCO solenoid valve failed because of its extensive time-in-service (about 20 years) coupled with the continuous air pressure applied at the diaphragm (about 80 psig). Plant staff planned to establish a periodic replacement schedule for the diaphragms. Westinghouse recommended that PSE&G inspect the no. 1 seal. For safety considerations (avoiding reduced inventory) Salem management, after consulting with Westinghouse and other licensees, elected to perform the maintenance by lowering the RCP onto the "backseat" formed by resting the radial bearing on the thermal barrier heat exchanger. Salem maintenance completed the maintenance activity safely. Although they found no seal damage the licensee replaced the no. 1 seal package.

- In January 1995, the inspectors learned that Unit 2 operated the entire previous cycle (5/93 to 10/94) with a closed drain valve in a common drain line for the Pressurizer Safety Valve loop seals. The valve should have been opened, but the licensee had not done an adequate post-modification lineup or adequate post-modification testing. The 10 gallons of water in the loop seals would create thrust loading on the safety valve discharge piping with the potential to deform the pipe, restricting flow. As a result, the loop seals could render the safety valves incapable of protecting the RCS from overpressurization. This issue is a candidate for escalated enforcement. (IR 95-02, not yet issued.)

- In December 1994 and January 1995, during startup from the refueling outage, Salem Unit 2 pressurizer code safeties leaked past the seats due (apparently) to dead weight and thermal loading on the discharge piping. As a result, Salem spent the period from December 25, 1994 to January 10, 1995, determining the cause of the leakage. Salem replaced the code safeties, adjusted the piping, and, as of January 31, 1995, had successfully reached normal operating pressure with no code safety seat leakage. (IR 94-35)

- Stuck trash rake affecting Unit 1; occurred several times. On November 15, 1994, the new rake stuck on the old trash racks in front of the 13B CW pump intake, forcing a power reduction to 850 MWe. On December 7, 1994, the new rake again stuck on the old trash racks in front of the 13B CW pump intake, forcing a power

reduction to 850 Mwe. On January 3, 1995, the new rake stuck in front of 12B CW pump. On January 9, 1995, the old rake stuck in front of the newly replaced racks in front of 13B CW pump intake. PSE&G replaced the racks in front of 13B CW pump, and plans to replace the racks in front of 12B and 11A by the end of February. All other racks have been replaced at least once. (IR 94-31)

- Unit 1 operators commenced a forced shutdown on January 6, 1995, due to inoperable 1A Safeguards Equipment Controls (SEC). The power supply failed. Although the Alternate Test Insertion (ATI) circuit had been turned on (see below) and had produced periodic alarms, the techs and operators did not pursue the alarms (due to previous experience) and apparently took a power reduction that could have been avoided. The licensee contracted an EMI specialist in mid-February to investigate the frequent ATI test faults. Engineering, supported by the EMI specialist, determined that EMI levels in the SEC cabinet, although high enough to cause ATI alarms, do not impact the ability of the SEC to perform its designed safety function. Engineering is actively pursuing the EMI specialist's recommendations to improve the immunity of the ATI to EMI and to prevent future spurious ATI alarms. (IR 94-31)

- Grass intrusion into unit 1 Circ Water on December 11, 1994. Operators took 13B out of service to clean the water box. 13A tripped on high d/p. Operators reduced power at 5% per minute. The 12B and 12A emergency tripped. Operators reduced power to 51% while restoring the 12A and 12B CW pumps to service. (IR 94-31)

- Unit 1 operators initiated an unplanned shutdown on December 9, 1994, for inoperable Safeguards Equipment Control cabinets. The three SEC cabinets for each unit control sequencing of safety related loads onto the 4kV vital busses. A stuck test switch (not immediately identified) caused a fault indication in the test circuit. Technicians took the test switch panel from the 1B SEC to aid in trouble-shooting 1A, and inadvertently caused a stuck switch in 1B SEC. Operations and maintenance staff concluded that a common mode failure might exist, declared the SECs inoperable, and started the shutdown. The stuck switch in 1A SEC existed from the previous surveillance on November 23, but operators did not detect the fault since they had taken the Automatic Test Insertion circuit out of service due to "nuisance" alarms. (IR 94-31)

- On November 28, 1994, no. 2 Station Power Transformer lost power as a result of a modification in the unit 2 control room actuating ground fault protective relaying. The worker performing the mod introduced a ground fault on the relay, in conjunction with an existing ground elsewhere on the ungrounded system (by design).

- Also on November 28, 1994, the no. 5 substation in the 13 kV ringbus lost power, causing the TSC to lose power. The cause was insulators arcing over. The TSC diesel started, but the TSC ventilation failed to start as a result of a blown fuse. Fast transfers occurred successfully on both units.

- Breakdown of insulation on 4kV supply cable to the unit 1 vital buses (November 21, 1994); caused by liquefied pulling compound dripping down onto the cable end between the dust boot and the heat shrink, providing a lowered resistance from the terminal lug to the ground strap.

- On November 18, 1994, the 4T60 disconnect opened causing the no. 4 station power transform to de-energize, interrupting one source of offsite power to each unit. Loads fast transferred at Unit 1, but 3 of 5 running circ water pumps lost power, requiring operators to reduce power. Unit 2 lost spent fuel pool cooling for 17 minutes since the other source of power was out due to the outage work. No apparent increase in SFP temp. No apparent cause for the disconnect opening. Power was restored five days later using no.2 SPT.

- On September 29, 1994, Salem Unit 2 operators initiated a manual reactor trip from 29% power following the inadvertent closing of two main steam isolation valves (MSIVs). The licensee was returning the unit to rated power following maintenance on one of the charging pumps. The operators were at the point in the power ascension procedure for closing main steam line drains. After acknowledging the order to close the main steam drains, the operator mistakenly closed two MSIVs. Operators initiated a manual trip. (See IR 50-311/94-24)

- On August 24, Unit 1 operators reduced power to 1% to repair the condensate system suction header. The header sustained damage to a support pedestal and several expansion joints when operators isolated No. 12 condensate pump to replace its mechanical seal. Pressure from back leakage through the closed pump discharge bypass valve generated sufficient force to shift the suction header. The licensee repaired damaged components and modified the condensate procedure to change the sequence of valve manipulations operators follow when isolating a condensate pump. (See IR 50-272/94-19)

- On July 14, 1994, Salem Unit 1 operators initiated a manual reactor trip from 100% power following a complete loss of circulators. A lightning strike caused the Unit 1 circulator supply breakers to open on undervoltage. Operators responded correctly in tripping the reactor as condenser vacuum decreased rapidly. (See IR 50-272/94-14)

- On July 2, 1994, the licensee identified an unisolable flange leak from an unused instrument line on the No. 22 reactor coolant pump (RCP). At the time of the discovery, the licensee was attempting to repair the flange. The licensee cooled down and depressurized the plant (taking the plant from Mode 3 to Mode 5). The licensee established a freeze seal on the leaking line and replaced the existing flange and piping with a blank flange. (See IR 50-311/94-14)

- On June 29, 1994, Salem Unit 2 experienced a reactor trip from approximately 6% reactor power due to low steam generator water level. Prior to the trip, while increasing power to 14%, a

feedwater oscillation caused a high water level condition in one steam generator. The high steam generator water level initiated a feedwater isolation. The level oscillations occurred when the minimum flow valve cycled open and closed. The licensee changed procedures to improve operator control of the minimum flow valve. The licensee also changed the gain in the valve controls. The operator reduced power to within the capacity of auxiliary feedwater; however, before water level could be stabilized in all generators, the no. 23 steam generator reached its low level setpoint causing the reactor trip. (See IR 50-311/94-14)

- On June 10, 1994, while operating at 97% power, the Salem Unit 1 reactor automatically tripped following a main generator trip. The licensee concluded that a potential transformer failed, causing the main generator output breakers to open, leading to the reactor trip. The licensee sent the potential transformer to an outside facility to determine the cause of the component failure. (See IR 50-272/94-13)

- On April 7, 1994, the Unit 1 operating crew rapidly reduced power in response to severe river grass intrusion at the circulating water intake structure. Salem Unit 1 tripped from 25% power during maneuvers to shut the plant down. Subsequent to the reactor trip, the plant experienced a series of safety injections which resulted in loss of the pressurizer steam bubble and normal pressure control. In addition to the reactor trip and safety injections, certain valves that are required to operate, failed to close. On April 8, the NRC dispatched an Augmented Inspection Team to the site to review the causes and safety implications of the multiple failures in safety-related systems during the event and possible operator errors. (See AIT Report 50-272/94-80 and 50-311/94-80)

b. Assessment

Unanticipated equipment deficiencies continue to dominate performance of the Salem units. In February, both units shutdown to correct design inadequacies with the Solid State Protection System. Problems with main steam atmospheric relief valve controls delayed unit 1 startup until February 27. Although operators restarted Unit 2 on February 11, low seal leakoff flow from the no. 21 Reactor Coolant Pump seal required a shutdown on February 19. As of January 31, Salem Unit 1 had continuously operated for more than 150 days, although Unit 1 operators had to reduce power six times in six weeks due to equipment problems from November 6, 1994 to December 17, 1994. On the other hand, the Salem units have experienced only one reactor trip in the six months beginning August 1, 1994, as compared with five trips in the period from February 1, 1994 to August 1, 1994. Operators have begun to take significantly increased ownership for plant performance and safety. Their involvement in insuring nuclear and personnel safety during the inspection of the no. 23 Reactor Coolant Pump seal illustrates their leadership in identifying and preventing pitfalls in plant activities. Maintenance management identified that lack of supervisory oversight of job briefings had resulted in ineffective worker preparation for maintenance

activities. Steps have been taken to improve the job briefings. System engineering support for daily operations and maintenance activities continues to require significant improvement. While some improvement has been noted in design engineering support for daily activities, plant and design engineering senior management involvement was frequently required to force communication between the organizations. Plant support organizations continued to demonstrate excellence in their activities.

Overall, the number of challenges to uneventful Salem operations continued at a high rate in comparison to other plants, such as, Hope Creek. Senior PSE&G management has implemented a number of changes intended to address the need for change, including replacing the Chief Nuclear Officer, the Salem General Manager, the quality assurance and nuclear safety review manager, the station quality assurance manager, the mechanical maintenance manager, the planning manager and the plant technical support manager. Senior PSE&G management met with Region I senior management on March 12, to present a proposed Salem reorganization. The new organization would add a unit 1 director and a unit 2 director reporting directly to the Salem general manager. The new organization would also add (for each unit): a unit operations manager, unit senior nuclear shift supervisor, unit maintenance manager, unit planning manager, and unit outage planning manager. Salem management has taken steps to increase the emphasis on accountability from the Vice President of Operations down through all levels of management to the workers. Leon Eliason initiated a team of consultants and nuclear industry senior managers to determine why PSE&G actions to improve Salem performance have been ineffective. In addition, Mr. Eliason has initiated a process to bring about a "step change" in Salem performance. This process is intended to hold managers accountable for achieving results, as opposed to past emphasis on generating activity. Although some examples of improved performance have occurred, especially in the areas of operations and maintenance, it cannot yet be determined whether PSE&G actions will result in lasting changes.

c. <u>Performance Indicator Data</u>

FOR AEOD TO UPDATE

Units 1 and Unit 2:

d. <u>Recently Identified Technical Safety and Managerial Challenges (of last 12 months)</u>

- The Salem unit 2 refueling outage, scheduled for 77 days, extended to 110 days as a result of equipment problems, including pressurizer code safety valves leaking past the seat.

- Both Salem units shutdown in early February 1995 due to inadequate design of the Solid State Protection System. A single steam line failure in the turbine building could have rendered both trains of SSPS inoperable with the result that operators would have been required to manually initiate Safety Injection.

- Both Salem units suffered performance failures in the controls for the main steam safety atmospheric relief valves. These controls have a long history of inadequate control and maintenance. In the most recent problems, the licensee *again* discovered unexpected components in the control circuits, demonstrating ineffective corrective action for the level IV violation after the April 7, 1994, event.

- A number of allegations with potential safety significance have been <u>substantiated</u>, including:

  - inadequate PORV design, with the result that redundant capability to limit RCS pressure under low temperature conditions had not been assured (an USQ with the potential for escalated enforcement);

  - installation of non-Q limit switches in safety-related applications, two of the eight (for both units) head vent valves, with the result that repeat problems with safety related part controls raise programmatic questions about the Salem ability to control safety related maintenance (currently being reviewed for escalated enforcement); and

  - incorrect Technical Specification definition of controlled leakage, with the result that Safety Injection flow supplied to the core, in the event of a RCP seal supply line failure during an accident, could have (and at times would have) been less than assumed in the accident analysis (no violation was issued, since Salem was always in compliance with the Technical Specification requirements).

  The Senior Resident Inspector has personally seen evidence that the alleger made the concerns known to the licensee and that the licensee did not respond in a timely, conservative fashion. Although some of the allegations from the same source were unsubstantiated, several more have yet to be addressed.

- The licensee discovered on October 15, 1994, 2 days into the unit 2 refueling outage, that a valve in the pressurizer code safety valve loop seal drain line had been closed throughout the operating cycle from July 1993 until October 1994. The immediate safety implication is that the licensee could not assure, based on any analysis existing as of March 15, 1995, that the water hammer from the impact of the water in the loop seal on the valve discharge line would not deform the discharge pipe and restrict flow to less than that required by design. The licensee is currently performing an analysis to demonstrate that the valves could have performed their intended function, however, engineering stated that analysis will not be able to show that the thrust loads will be within code allowable limits.

- Service Water (SW) Leaks: The licensee is completing a seven year pipe replacement project that will replace most (about 19,000 linear feet are safety related) of the safety related SW piping with 6% moly stainless steel. This project will probably continue through 1997. Currently, approximately 90% of the safety related

portion of the project has been completed, including the majority of the SW piping in containment, diesel bays, SW intake structure, and auxiliary building. Based on NRC inspection, SW pipe replacement project is progressing satisfactorily as scheduled.

- Unit 2 Sustained Operation of Greater Than 100% Power: during the recent outage, the licensee confirmed erosion of the feedwater flow nozzles resulting in incorrect online calorimetric data. Upon discovery, licensee immediately reduced power for both units, and began adjusting instrument setpoints to insure conservative operation. The licensee concluded that 102.5% was the exact power level and operating at that power level did not invalidate any of the UFSAR Chapter XV conclusions.

- Work Control Problems: During the Unit 2 refueling outage, the licensee and the NRC identified additional examples of failure to follow established procedures relative to the control of maintenance work activities. These examples were similar to those previously identified during the Unit 1 outage, November - December 1993.

- In September, PSE&G named Leon Eliason as the new Chief Nuclear Officer (replacing Steven Miltenberger), and President of a newly structured nuclear business unit. Eliason's appointment was effective October 1, 1994. He reports directly to PSE&G Chairman Ferland. The nuclear business unit will encompass all operational and support activities for both Salem units and Hope Creek. Since October senior management has also appointed a new Salem general manager and a new quality assurance and nuclear safety review manager; they have replaced the station quality assurance manager, the mechanical maintenance manager, and the planning manager. As discussed above senior PSE&G management met with Region I senior management on March 12, to present a proposed Salem reorganization. The new organization would add a unit 1 director and a unit 2 director reporting directly to the Salem general manager. The new organization would also add (for each unit): a unit operations manager, unit senior nuclear shift supervisor, unit maintenance manager, unit planning manager, and unit outage planning manager. Salem management has taken steps to increase the emphasis on accountability from the Vice President of Operations down through all levels of management to the workers. Leon Eliason initiated a team of consultants and nuclear industry senior managers to determine why PSE&G actions to improve Salem performance have been ineffective. In addition, Mr. Eliason has initiated a process to bring about a "step change" in Salem performance. This process is intended to hold managers accountable for achieving results, as opposed to past emphasis on generating activity.

- Grass Intrusion at Circulating Water Inlet Structure: The licensee documented this plant vulnerability for years, yet the condition continues to provide unnecessary plant challenges. An AIT was dispatched to the site on April 8, 1994, to investigate the plant transient that resulted from severe grass intrusion on

April 7. The AIT concluded that the vulnerability of the design was previously recognized and modifications to improve the system had not yet been implemented.

- Unaddressed Equipment Problems: The staff documented numerous cases of known equipment deficiencies factoring significantly into Salem events. The AIT of April 1994 found that management allowed equipment problems to exist that made operations difficult for plant operators.

- In an effort to improve management accountability and performance, in July 1994 PSE&G terminated approximately 55 non-bargaining unit members of the Nuclear Division for inadequate performance. Eleven of the terminated employees were assigned to Salem.

- Operators continue to face many challenges posed by equipment failures. Recent examples include the control air system, the emergency diesel generator air start system, and the main feedwater pump hydraulic control systems.

3. ESCALATED ENFORCEMENT ACTIVITIES

- The NRC issued a Level III Violation on March 8, 1994, documented in NRC Inspection Report 50-272 and 311/93-23; 50-354/93-25. The violation was based on multiple examples of PSE&G's failure to follow procedures and their failure to properly control safety-related activities.

- The NRC issued four Level III and two Level IV violations and imposed a Civil Penalty of $500,000 on October 5, 1994. The violations were documented in NRC Letter EA 94-112 and were based on the licensee's performance prior to and during the April 7, 1994 event.

- On February 8, 1995, PSE&G met with NRC at Region I in King of Prussia to discuss the findings of the Office of Investigation relative to assertions of violations involving 10 CFR 50.5 "Deliberate Misconduct," and 10 CFR 50.7 "Employee Protection."

- On March 17, 1995, an enforcement panel will review three violations for potential escalated enforcement. The violations involve:

  - failure to control materials used in safety related applications (non-Q limit switches installed in two reactor head vent valves);

  - failure to control a modification to insure that it was correctly implemented (installing the loop drains for the pressurizer code safety without insuring that the drain valves were properly aligned, or insuring that post modification testing verified that the drain performed its intended function); and

  - a repeat failure to comply with the Technical Specification action statement requirement for an inoperable PORV.

4. IPE INSIGHTS

- Salem submitted its IPE to the NRC in July 1993; the document is still under NRC review.

III. ANALYSIS/ASSESSMENT

1. PREVIOUS SALP RATINGS AND OVERVIEW

a. Previous SALP Ratings

Functional Area	June 19, 1993	November 5, 1994
Operations	2	3
Maintenance/ Surveillance	2	3
Radcon	1	N/A
Emergency Preparedness	1, Declining	N/A
Security	1	N/A
SA/QV	2	N/A
Engineering & TS	2	2
Plant Support	N/A	1

Current assessment period: November 5, 1994 to March 9, 1996.

b. SALP Overview (derived from the summary paragraph of each SALP section):

OPERATIONS

On January 12, 1995, the SALP board met to discuss PSE&G's performance at Salem during the period from June 19, 1993 to November 5, 1994. The board concluded that operators generally responded appropriately with good command and control to the many plant trips and operational transients that occurred over the SALP period. Likewise, they demonstrated good proficiency in making emergency declarations for events for which such declarations should have been considered. However, performance over the assessment period demonstrated significant weaknesses in several areas. Operators did not practice ownership of the plant and did not aggressively enlist other plant departments to resolve longstanding equipment problems which frequently challenged them in normal and upset plant conditions. A lack of an appropriate questioning attitude by operators resulted in anomalous indications, or conditions being unnoticed or not understood and not being acted upon. A lack of guidance for and training of operators on operability decisions resulted in some decisions being nonconservative or having weak technical bases. Examples of nonconservative approaches to entering and exiting LCOs occurred over the period. Some difficulties were experienced managing and controlling outage activities. Poor self assessment within the Operations department coupled with ineffective independent assessment of Operations by the Quality Assurance and Nuclear Safety Review organization contributed to the continuation of performance problems throughout most of the period.

MAINTENANCE/SURVEILLANCE

The board concluded that performance weaknesses were evident in maintenance programs and activities, such as procedural adherence and adequacy, the feedback process, specification of post-maintenance testing requirements, and control of work activities by numerous onsite groups. Management has improved its safety focus in prioritizing and scheduling maintenance activities. However, management oversight of corrective action program activities has been weak as evidenced by the high recurrent equipment failure rates. Inconsistencies in troubleshooting activities and root cause analysis contributed to the delay in correcting recurring problems. Material condition of the plant continues to improve, but there remain several areas that need improvement. Although the in-service testing program was adequate, management did not effectively resolve self assessment findings. Programs for in-service inspection, erosion/corrosion and steam generator leakage monitoring were adequately implemented.

ENGINEERING

The Board concluded that Engineering performance was inconsistent, with substantial variation in quality. The quality of the discipline design work was good, with significant engineering management focus shown in several modification activities. However, engineering work priorities did not always reflect plant needs. In several significant programmatic areas in which the Engineering organization had an important role, performance was, on balance very good. Significant problems, nonetheless were noted associated with root cause assessments and with equipment problem resolution. The fact that there existed engineering capability, that when focused by station management and brought to bear on important issues, demonstrated the ability to achieve very good performance, suggested that a significant aspect of the problem was associated with the effective engagement of available engineering expertise in activities important to safe plant operations, such as in root cause assessment and equipment problem resolution.

PLANT SUPPORT

The Board concluded that plant support functions contributed effectively to safe plant performance. Performance in the radiation protection area continued to be a significant licensee strength. Well trained technicians and staff coupled with effective management resulted in aggressive ALARA program implementation with significant dose savings realized. Excellent performance in the radiological environmental monitoring and effluent control programs was again noted. There was continued good performance in the emergency preparedness area. Security program performance continued to be a strength. Fire protection program implementation was substantially improved.

2. LICENSEE RESPONSE TO PREVIOUS SALP FUNCTIONAL AREA WEAKNESSES/RECENT LICENSEE PERFORMANCE TRENDS (in the last year)

- OPERATIONS

The licensee response to the SALP did not provide detailed information on plans to address performance inadequacies. The response generally agreed with the NRC's assessment of Salem performance. In addition, the response stated an intention to correct Salem performance problems. Since the response letter was issued, senior PSE&G management has initiated an effort to determine the cause of the ineffectiveness of previous corrective actions. In addition, PSE&G management proposed reorganizations of several organizations (discussed in more detail below), and implementation of a "step change" process intended to produce results, rather than activity without results.

The proposed re-organization would quickly bring the unitization concept to fruition for Salem Operations. Two plant directors (one for each unit) would report to the Salem General Manager. In turn, two operations managers (one for each unit) would report to the directors, and each operations manager would have responsibility for a unit operations department, including a Senior Nuclear Shift Supervisor and the shift complement necessary to support operation of that unit. It is important to note that, as of March 15, the licensee had not reached a final conclusion to implement the propose organization.

In response to the April 7 event, Operations management provided improved guidance to operators for command and control and conservative operation of the plant.

In response to NRC concerns, Operations management developed a flow chart for operability determinations. Inspectors have occasionally noted weak or incorrect interpretation of Technical Specifications.

The inspectors have also noted that the Operations Manager has convinced the department staff that change is necessary, and fostered an increasing sense of ownership and team work.

- MAINTENANCE AND SURVEILLANCE

Secondary/BOP equipment deficiencies pose significant challenges to plant operations, e.g. manway failure, condensate header damage, COPU filter replacement, CW travelling screens, FW feed control at low power levels.

In order to improve overall performance and response to emergent issues, PSE&G reorganized the Maintenance Department. Changes included replacing the single Maintenance Manager role with three new positions: 1) Mechanical Maintenance Manager, 2) Controls Maintenance Manager, and 3) Planning Manager. PSE&G began to unitize these departments. The proposed (as of March 15) reorganization would further unitize maintenance planning management structures. As of March 15, unit 1 and unit 2 had separate outage planning managers. The proposed reorganization would provide separate (non-outage) planning managers and maintenance managers for each unit, reporting to the unit directors for their respective units. The

unit maintenance managers would oversee mechanical, electrical and I&C maintenance for their respective units (recombining the disciplines under one maintenance manager for each unit).

To address the existence of long standing equipment problems, plant management required operators to develop a list of workarounds to be addressed by maintenance personnel in accordance with assigned priority.

- ENGINEERING AND TECHNICAL SUPPORT

Salem and corporate engineering have not consistently communicated well with operations, nor has operations communicated well with engineering. System engineering has not effectively prioritized their workload, nor have they effectively monitored equipment reliability, as demonstrated by the "workaround" list generated in response to this NRC identified concern. The system engineers did not receive training on operability or Generic Letter 91-18 until September 1994.

An NRC observation related to the Salem rod control issue was that the initial troubleshooting efforts lacked clear leadership and delegation of responsibilities. This resulted in the efforts narrowly focusing on the most recent system malfunction without adequate attention to the repetitive nature of the failures and the need to determine and correct the root cause. The failure of PSE&G to determine the root cause of the failures resulted in numerous aborted startup attempts. The team did observe significant improvements in the control of troubleshooting and root cause determination during the inspection. A management oversight team was initiated to review all I&C troubleshooting activities in an effort to reduce events caused by troubleshooting.

In late February 1995, PSE&G announced a reorganization of the Nuclear Engineering department (corporate engineering). PSE&G management redirected resources no longer required to support the Salem revitalization project (since it would be substantially complete in 1995) to better support Salem and Hope Creek operation. The effects of this reorganization have not yet been demonstrated.

In addition, Salem management rotated the Technical Support manager to the Quality Assurance and Nuclear Safety Review department to provided improved oversight of Quality Assurance and corrective action programs. Salem management had not named a permanent replacement Technical Support manager as of March 15.

- PLANT SUPPORT

The NRC noted that PSE&G continued to perform at a noteworthy level in the area of radiological protection through the end of 1994, especially during the recent Unit 2 refueling outage.

The licensee's annual partial-participation emergency preparedness exercise was conducted on June 23, 1993. On-site response to the simulated emergency was very good. An exercise strength was Emergency Response Manager command and control. No exercise weaknesses were identified. Significant areas for potential improvement were maintenance

team tracking from the Operational Support Center and public address system operability in the Technical Support Center.

The PSE&G security program continues to be effectively directed towards public health and safety. However, certain assessment aids have deteriorated to the point where maintenance was no longer effective.

- SAFETY ASSESSMENT/QUALITY VERIFICATION

In July 1993, the licensee formed a Comprehensive Performance Assessment team (CPAT) which conducted a special assessment of safety issues and recent plant events using an integrated MORT investigatory analysis. The CPAT developed comprehensive root causes for these events, and the licensee has formed task teams charged with developing corrective actions. PSE&G has held periodic meetings with the NRC to discuss CPAT findings, and the NRC continues to monitor licensee progress in this area.

3. LICENSEE PERFORMANCE STRENGTHS AND WEAKNESSES *

Salem performance continues to be inconsistent.

- Capacity factor has been low due to refueling outages at both units and numerous forced outages and power reductions resulting from problems with SPPS, MS-10s, pressurizer code safety valves, rod control, and to support PORV replacement as well as equipment modifications following the April 7 event. Grass fouling of circulators and numerous plant trips contribute to the low capacity factor as well.

Strengths:

- The licensee continues to increase resources for a material condition improvement program. The NRC has observed noticeable improvement in the material condition of the plant, indicating that the licensee has been earnest in the implementation of improvements.

- Radiation protection program implementation continues to be very strong.

- When problems or conditions are self-identified and self-detected, event response and root cause determination are through and comprehensive, particularly when the matter is the subject of NRC attention. In other cases, the licensee's performance is considered weaker, as identified below.

- PSE&G has responded to identified performance and management weaknesses relative to approach to problem resolution by initiating the following actions:

- PSE&G senior management has replaced the mechanical maintenance manager, the planning manager, QA manager with personnel from within the PSE&G organization, and has filled the General Manager position and the Quality Assurance and Nuclear Safety Review position with new personnel from outside the company. In addition, PSE&G management proposed reorganizations of several organizations and implementation of a "step change" process intended to hold managers accountable for producing results.

- Verifying the effectiveness of numerous supervisors and managers and changing the incumbent when deemed appropriate;
- Pursuing unitization of the operations organization; maintenance and planning organizations are unitized.
- Implementing the existing performance assessment tools to improve accountability from the highest levels of management down to rank and file workers;
- Forming dedicated teams to implement the corrective actions developed in response to the CPAT findings.

Weaknesses:

Salem performance continues to be weak in:

- Planning
- Control of maintenance;
- System Engineering and Technical Support
- The ability to do root cause determination;
- Corrective action effectiveness due to inadequate root cause assessment;
- Inadequate approach to problem resolution (i.e., general tendency to fix problems or conditions based on the most probable cause without assessment or understanding of all possible causal factors.) Examples include, but are not limited to: maintenance and modifications to the atmospheric relief valves, problems with main feedwater regulating valve controls and feedwater pumps, maintenance of the Safeguards Equipment Control systems, and initial response to cracked diesel liner issues, failure to identify elevated reactor power in 1992, and failure to recognize generic implication of rod control problems.

4. NRC TEAM INSPECTIONS WITHIN THE LAST YEAR

Area/Date	Findings
Augmented Inspection Team (AIT) April 15-16, 1994	An AIT was formed to review causes and safety implications associated with a series of malfunctions experienced during a plant transient and subsequent trip.
Customized Inspection Program Team August 15-16, 1994	The team concluded that increased inspection is warranted in the areas of maintenance and control systems. Also expressed concern about licensee failure to proactively correct equipment deficiencies before they lead to plant events.

SWSOPI September 5-23, 1994 Monitoring of Licensee's Self-Assessment	Report on licensee's assessment not yet issued.

IV. INSPECTION PROGRAM STATUS

1. STATUS OF INSPECTIONS

The inspection program status is reflected in attached MIPS report #2. The data is current as of the date of the MIP. The MIP indicates that inspection program is on-track with the planned resource allotment; no significant shift in inspection activities is warranted.

2. PROPOSED CHANGES TO MIP

- Unit 1

  A. DRSS -

  B. DRS -

  C. DRP

- Unit 2

  A. DRSS -

  B. DRS -

  C. DRP -

3. SIGNIFICANT ALLEGATIONS AND INVESTIGATIONS

Three Salem allegations are related to or resulted from a December 3, 1992 altercation between two SRG engineers and the former General Manager (GM), Operations Manager (OM), and, to a lesser extent, the Manager-Quality Assurance & Nuclear Safety Review (QA&NSR). OI substantiated harassment and intimidation (H&I) in this case. Enforcement conferences were conducted with the licensee and the affected managers on February 8 & 23, 1995. Some of these managers engaged in willful misconduct (pre-decisional). Enforcement action is pending.

Since the licensee's effort to terminate several employees for poor performance on July 18, 1994, the Region has received additional multifaceted allegations from two terminated employees that are currently under review. One of these pertained to 23 separate management, operations, and engineering concerns. These were presented to NRC personnel in a face to face meeting on August 8, 1994. One concern pertaining to the low pressure over protection system (POPS) was substantiated. Inadequate design compromised the redundant capability of the PORVs to limit RCS pressure under low temperature conditions. An enforcement panel agreed to proceed with additional action after OI completed its review of potential willful misconduct and harassment and intimidation issues. An additional multifaceted allegation involved both technical issues and potential H&I issues. This allegation concerns six technical issues raised regarding the environmental qualification of equipment. Currently, the EQ issues are being reviewed by DRS and the

wrongdoing issues are being reviewed by OI. This allegation also involved a terminated employee. The NRC received this allegation from senior PSE&G management.

Additional allegations with potential safety significance have been substantiated. Non safety related limit switches were installed in two of eight reactor vessel head vent valves (safety-related application), and an incorrect Technical Specification definition of controlled leakage, with the result that Safety Injection flow supplied to the core, in the event of a RCP seal supply line failure during an accident, could have (and at times would have) been less than assumed in the accident analysis (no violation was issued, since Salem was always in compliance with the Technical Specification requirements).

Collectively, these allegations implicate the previous station management's ability to personally resolve and address safety issues. Regarding the December 1992 altercation, this incident and the two related allegations appear to be due to management's confrontational attitude with QA&NSR personnel. Since these managers have been replaced, this concern appears to have dissipated. The EQ allegation and its OI component, and the 8/94 allegation appear to stem from a tendency of PSE&G to manage by memo. They are not effectively using their root cause programs. Management's failure to identify and resolve root causes was a direct contributor to these two allegations. Based on the SALP (50-272/93-99) and a recent engineering inspection (50-272/95-01), this appears to be a continuing concern.

4. OPEN ITEM STATUS

BACKLOG/No. GREATER THAN 2 YRS

(Unit 1 and 2 - Common) 62/7

NOTE: The large number of open items is due to the issuance of an Appendix R/Fire Protection Team Inspection Report in October 1993 and an EDSFI Team Inspection Report in November 1993.

5. OUTSTANDING LICENSING ISSUES

- GL 89-10 (MOV) - technical differences between NRC/PSE&G. (Hope Creek also)
- EDG amendment - meeting held May 11, 1992 to resolve issues.
- TS amendment to resolve AFW/containment spray issue (see Section II.2.a).
- Increase in surveillance test intervals and AOT for reactor trip and ESFAS.
- Install new digital feedwater control system.
- Evaluation of Control Room Design Deficiencies that were not corrected.
- Bulletin 88-08 (Thermal Stress in Piping Systems Connected to the RCS) - licensee is revising their response.

6. LOCAL/STATE/EXTERNAL ISSUES

a. NJ DEPE/BNE

- Now providing input/comments on all PSE&G licensing change requests.
- High interest in resident inspection accompaniment.
- Continuing interest in Salem cooling tower issue: When Salem's renewable variance for the use of the Delaware River as a heat sink came up for renewal in 1984, New Jersey environmentalists appealed to the state to not renew the variance. In 1990, NJ DEPE issued a "draft order" requiring PSE&G to build two cooling towers to support the Salem units' operation. PSE&G responded to the state's order with a 56-volume comment, and the issue is currently under review by NJ DEPE. Recent NJ DEPE decision not to require cooling towers.
- State inspectors generally accompany all AIT efforts.

b. Other (Recent Media Interest)

- Large interest in recent AIT (April 26, 1994) exit meeting and subsequent enforcement conference (July 28, 1994). Several local television and newsprint representatives attended. Also, the conference was attended by representatives of Senator Biden's staff.

SALEM EXECUTIVE SUMMARY

LICENSEE PERFORMANCE STRENGTHS AND WEAKNESSES

Salem performance continues to be inconsistent.

- Capacity factor has been low due to refueling outages at both units and numerous forced outages and power reductions resulting from problems with SPPS, MS-10s, pressurizer code safety valves, rod control, and to support PORV replacement as well as equipment modifications following the April 7 event. Grass fouling of circulators and numerous plant trips contribute to the low capacity factor as well.

Strengths:

- The licensee continues to increase resources for a material condition improvement program. The NRC has observed noticeable improvement in the material condition of the plant, indicating that the licensee has been earnest in the implementation of improvements.
- Radiation protection program implementation continues to be very strong.
- When problems or conditions are self-identified and self-detected, event response and root cause determination are through and comprehensive, particularly when the matter is the subject of NRC attention. In other cases, the licensee's performance is considered weaker, as identified below.
- PSE&G has responded to identified performance and management weaknesses relative to approach to problem resolution by initiating the following actions:
- PSE&G senior management has replaced the mechanical maintenance manager, the planning manager, the technical support manager, and the Salem QA manager with personnel from within the PSE&G organization; and has filled the General Manager position and the Quality Assurance and Nuclear Safety Review position with new personnel from outside the company.
- Verifying the effectiveness of numerous supervisors and managers and changing the incumbent when deemed appropriate.
- Pursuing unitization of the operations organization; maintenance and planning organizations are unitized. Additional changes have been proposed to further unitize operations, planning, and maintenance managers below the proposed plant directors.
- Implementing the existing performance assessment tools to improve accountability from the highest levels of management down to rank and file workers.
- Forming dedicated teams to implement the corrective actions developed in response to the CPAT findings.
- Initiating a team of consultants and senior managers from other utilities to determine the cause of the ineffectiveness of PSE&G corrective actions for Salem to date.

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* Developing a "step change" process intended to hold managers accountable for achieving measured performance improvements.

Weaknesses:

Salem performance has been weak in:

* Planning.

  Salem unnecessarily rendered an entire train of Service Water inoperable for a valve repair that didn't need to be done, and didn't get completed. Salem planned maintenance on an EDG to trouble shoot a non-safety portion of the test controls, without determining if parts were available; this extended the time in the LCO.

* Control of maintenance.

  Level III violation in the Unit 2 outage for lack of procedure adherence and lack of tagging control. Mechanics changed the oil in the wrong component in the AFW pump, and unintentionally "adjusted" the overspeed trip test device. The Salem Unit 2 PORVs were replaced with the "wrong" internals (not the parts intended). The correct internals were subsequently installed during the recent Unit 2 outage.

* Engineering and Technical Support.

  System engineering has poorly trended equipment reliability (for example, the Diesel air start system, the control air system). Engineering (corporate and system) has not communicated well with operations (for the most part, the operators don't know who they are). System engineering has not been involved in operability decisions, and was not trained on operability (Generic Letter 91-18) until I made a big issue out of it.

* Recognition of the need to do root cause determination.

* Corrective action effectiveness due to inadequate root cause assessment.

* Inadequate approach to problem resolution (i.e., general tendency to fix problems or conditions based on the most probable cause without assessment or understanding of all possible causal factors. Examples include, but are not limited to the licensee's initial response to cracked diesel liner issues, failure to identify elevated reactor power in 1992, and failure to recognize generic implication of rod control problems.)

GENERAL OBSERVATIONS:

Organization may not have sufficient level of knowledge relative to managing change based on observations by DRP and DRS inspectors.

Until recently, the Salem organization never engaged in attempting to benchmark itself relative to other utilities, including Hope Creek.

New emphasis on accountability, ownership of problems.

The July 1994 termination of 50-60 personnel appears to have been well received (by those who were not terminated). Generally positive comments from remaining staff acknowledging that there were several weak performers that failed to contribute to overall quality or safety.

While J. Hagan has been pushing for more supervisory field time, increased first line supervisory presence is not very apparent. However, there is a noticeable increase in the presence of middle management level personnel.

There are several examples recurring problems in BOP (service air, and feedwater) and some safety-related systems (EDG air start) have the potential to affect nuclear plant performance.

It is not clear, that the maintenance organization and system engineering organizations understand and appreciate the need to change. Unable to agree on meaningful improvement strategy unless imposed from the top down. Passive attitude seems to exist relative to change. Taken up with day-to day crisis management. Still tend to focus on most immediate proximate causes associated with an event.

While management is driving change, noticeable improvement in plant performance and personnel attitude and enthusiasm for determining and implementing improvement strategies and plans is not yet apparent.