U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-272/89-17

Docket No. 50-272

License No. DPR-70

Licensee: Public Service Electric and Gas Company
P.O. Box 236
Hancocks Bridge, New Jersey 08038

Facility Name: Salem Unit No. 1

Inspection At: Hancocks Bridge, NJ

Inspection Conducted: May 22-26, 1989

Inspectors: P. H. Bissett, Senior Operations Engineer
W. C. Lyon, Senior Reactor Engineer, NRR
S. M. Pindale, Resident Inspector

Approved by: P. K. Eapen 6/16/89
Dr. P. K. Eapen, Chief, Special Test Programs Section, EB, DRS (Team Leader) date

Inspection Summary: Special announced inspection on May 22-26, 1989 (Inspection Report No. 50-272/89-17).

Areas Inspected: Loss of RHR pump event on May 20, 1989 due to inadvertent nitrogen injection from an accumulator and the licensee action associated with it.

Results: The inspectors concluded that the licensee responded reasonably to this event with a few exceptions. These exceptions included operator error in selecting wrong switch from the rear panel to unblock the accumulator isolation valve; operator action to drain the RCS initially to bring the pressurizer level on scale; inadequate test procedures for conducting accumulator check valve full flow tests; inadequate abnormal operating procedures that did not assist the operators in realizing that the loss of RHR event is reportable under 10 CFR 50.72 and the event classification guide that also did not assist the operators in classifying this event adequately.

A complete engineering analysis of the event based on system response was not initially developed by the licensee. Recent operator training to mitigate the consequence of a loss of decay heat removal during shut down conditions permitted the operators to vent the RHR system using gravity fill from the RWST.

Two violations (inadequate review of the accumulator check valve test procedure and an inadequate event classification procedure that improperly classified this event) were identified.

DETAILS

1.0 Persons Contacted

1.1 Public Service Electric and Gas Company

Moses L. Burnstein, Principal Safety Review Engineer
Vi Jay Chandra, Technical Consultant, Engineering Sciences
Brian Connor, Technical Staff Engineer
Mahesh R. Danak, Salem Mech. Group
Allen Ho, Technical Consultant, Sciences
John Hudson, Offsite Safety Review Engineer
Stan LaBruna, Vice President Nuclear Operations
Craig Lambert, Nuclear Engineering Sciences - Manager
C. P. Lashkari, System Engineer
E. A. Liden, Manager-Offsite Safety Review
Bill McTique, Engineer
L. K. Miller, General Manager - Salem Operations
Steve Miltenberger, Vice President & Chief Nuclear Officer
John Musumeci, Operations Engineer
Pete Ott, NSSS Group Head - Technical Department
D. A. Perkins, Manager Station QA
Bruce Preston, Manager - Licensing & Regulation
Glenn A. Roggio, Station Licensing Engieer
John Ronafalny, Manager-Nuclear Engineering Services
Pell White, Technical Manager

1.2 United States Nuclear Regulatory Commission

Kathy Halvey Gibson, Senior Resident Inspector

2.0 Salem Unit 1 Loss of Residual Heat Removal (RHR) System Pumps on May 20, 1989

On May 20, 1989 Salem Unit 1 lost both of its RHR pumps for about fifty minutes due to an inadvertent injection of nitrogen from accumulator No. 13 to the RHR pump suction piping. This inadvertent injection took place while the operators were conducting full flow testing of accumulator check valves after recent maintenance. Each accumulator test consisted of unblocking the appropriate accumulator isolation valve (SJ54) from the back of panel 1RP4, stroking the valve from fully closed to fully open and returning the valve to the fully closed position after the test. Accumulators 11 and 12 had been satisfactorily tested, and the pressurizer water level indication had increased from 10% to 34% due to the injected water.

The Unit was recently refueled and the reactor vessel (RV) head was reinstalled. The reactor coolant system (RCS) had been refilled to an indicated cold calibrated pressurizer level of 10%. Reactor coolant pumps (RCPs) had not been started and consequently the steam generator (SG) tubes and RV head contained air. Two pressurizer power operated relief valves (PORVs) were open, the pressurizer relief tank (PRT) was essentially empty, and the PRT rupture diaphragm was removed. All accumulators were filled to normal operating level and pressurized to approximately 600 psig.

The sequence of events for this occurrence is listed below:

2.1 Sequence of Events

Initial Conditions

Mode 5 (Cold Shutdown)
RCS average temperature = 92 F
RCS pressure = 14 psi
RCS filled to greater than center line
No. 12 RHR pump in service at 3000 gpm
Pressurizer level = 34%
RCS/Pressurizer vented to containment atmosphere
No. 13 accumulator pressure = 630 psig
Volume of nitrogen
in No. 13 accumulator = 491 cft at 630 psig
RWST level = 38.3 ft.

Time	Event
9:25 a.m.	Start discharge test of No. 13 accumulator.
	- wrong isolation valve unblocked.
	- discharge commenced, but operators could not reclose isolation valve.
	- proper isolation valve unblocked.

9:26 a.m. No. 13 accumulator isolation valve closed (total stroke time = 70 seconds).

- RCS pressure increased from 14 to 51 psig.
- Pressurizer level increased to greater than 100%.
- No. 13 accumulator pressure dropped from 630 to 62 psig.
- Control room supervisor ordered RH21 (RHR return to RWST) valve opened to drain pressurizer level on scale.

9:34 a.m. Pressurizer level back on scale.

- RHR flow to RCS at 1000 gpm due to RH21 open (approximately 2000 gpm diverted to RWST).
- No. 12 RHR pump motor amps steady at 44.
- RCS pressure at 35 psi.

9:35 a.m. RHR flow to RCS rapidly decreased to zero (RH21 still open).

- No. 12 RHR pump motor amps at 21-24 (operator reports pump sounds abnormal, however unlike cavitation).
- RH21 ordered closed. RHR flow paths, except recirculation flow path, isolated. (Control room supervisor believed No. 12 RHR pump may have failed mechanically).
- Pressurizer level continued to decrease (85%)

9:43 a.m. Operators placed No. 11 RHR pump in service.

- No. 11 pump motor amps identical to No. 12 (21-24 amps). No indicated RHR flow.
- Core exit thermocouples slowly increasing (about 1 degree/hour).
- AOP-RH1 and AOP-RH2 initiated.

9:45 a.m. Both RHR pumps removed from service.

- Operators realized that nitrogen had discharged from No. 13 accumulator and RHR system was air bound.
- Control room supervisor ordered the RHR system be vented.

9:45 - 9:58 a.m.	Venting both RHR trains. - RH6 (pump casing vent) and RH9 (discharge piping drain) valves open on each train. Could not verify system venting since those valves were hard piped into the auxiliary building sump (could not see into sump). - Operators could not immediately identify the location of RH13 valves (discharge piping sample line) to enhance venting. - RHR system vents ordered closed. - Started No. 12 RHR pump. No flow, low amps, pump removed from service.
9:59 a.m.	RH13 valves located and opened, venting locally verified, however it was very slow (low pressure). - Pressurizer level reached 23%.
10:05 a.m.	Reactor head vents open, however differential pressure was not sufficient to provide vent flow.
10:18 a.m.	Core exit thermocouples at 122° F. - Control room supervisor ordered SJ69 (RWST to RHR pump suction) valve open to flush air out of RHR system since venting was slow. - Pressurizer level increased from 23 to 56%. - Air, then water, issued from RHR vents and drains. - SJ69 closed, pressurizer level stable at 56%.
10:23 a.m.	No. 11 RHR pump placed in service.
10:28 a.m.	No. 11 RHR pump flow restored to 3000 gpm. - Pressurizer level steady at 56%. - Core exit thermocouples at 93° F.
10:37 a.m.	No. 12 RHR pump placed in service. No. 11 pump removed from service (RHR flow at 3000 gpm).
10:56 a.m.	Reactor head vents closed, AOPs exited.
2:50 p.m.	Surveillance test satisfactorily performed on No. 12 pump.
3:15 p.m.	Surveillance test satisfactorily performed on No. 11 pump.

Final Conditions:	RCS average temperature	= 93° F
	RCS pressure	= 31 psi
	Pressurizer level	= 57%
	RWST level	= 39.8 ft.

2.2 Evaluation of RCS/RHR System Responses

Preliminary analyses by the licensee indicated that about 1300 cft of nitrogen was injected into the reactor coolant system while the isolation valve for 13 accumulator remained open for about seventy seconds. (Note: 491 cft of Nitrogen at 630 psig expands into 2690 cft at 62 psig. The accumulator, 1350 cft, and the piping system up to the reactor coolant system, 35 cft, has a combined volume of 1385 cft.) As nitrogen entered the RCS it initially expanded to about 2307 cft at the maximum observed reactor pressure of 51 psig. At atmospheric pressure this injected nitrogen would have a volume of about 10,200 cft). Figures 1,2 and 3 depict the estimated RCS fluid conditions at critical stages of this event. Figures 4 and 5 present the behavior of key reactor parameters during this transient. From these observations, the licensee postulated the following behavior for the reactor coolant system during nitrogen injection:

At 0925 hours the initial rapid water injection into the cold leg compressed air trapped in the steam generators (SGs) and in the upper reactor vessel (RV) head. Water was forced into the pressurizer.

The high pressure nitrogen essentially emptied the cold leg at the injection point, followed by depression of the RV downcomer level and draining of the other cold legs into the depressed downcomer. Nitrogen passed through leak passages between the top of the RV downcomer and entered the RV head region. Displaced water continued to fill the pressurizer. Water in the cross-over pipes and in the cold leg side of the SG tubes probably prevented large quantities of nitrogen from escaping directly into the hot legs by way of the SG tubes. Some nitrogen may have vented into the RV head via the RV lower plenum and the core.

At 0926, the open Power Operated Relief Valves (PORVs) allowed the pressurizer to continue to fill. As water continued to flow into the pressurizer, the Reactor Coolant system (RCS) depressurized and nitrogen expanded into the SG tubes, the cold and hot legs, and the RV head, forcing more water out the surge line into the pressurizer. As nitrogen expanded into the upper hot leg region, nitrogen separated the water in the pressurizer from the RCS. Pressurizer level indication reached 100% and went off-scale high. Some water probably was carried over into the PRT.

RCS draining operations were initiated at 0929 and contributed to hot leg inventory reduction as two thirds of the water entering the RHR suction pipe was pumped into the RWST rather than being returned to the RCS cold legs. At 0935, continued reduction of water inventory in the hot legs led to the loss of RHR flow due to gas binding of the 12 RHR pump. However, the operators did not realize the RHR pumps were gas bound. At this time, pressurizer level indication was 85% and indicated RCS pressure was about 33 psig.

Between 0942 and 0945, RHR pump noise led the operators to incorrectly believe the operating 12RHR pump was damaged, and they started 11RHR. Since the RHR suction line was voided, 11RHR immediately became gas bound. The operators then realized the pumps were voided. They tripped both RHR pumps, terminated RCS draining, and initiated pump venting operations. About 25,000 gallons of water had been pumped from the RCS into the RWST. Indicated pressurizer level was still above 60% at 09:45.

The operators followed RV temperature closely after loss of RHR. They correctly concluded the slow temperature increase rate would allow adequate time for RHR restoration efforts. (Water injection via charging or safety injection pumps were available options, but the operators were concerned about the voided suction line and the possibility of ingesting nitrogen into these pumps as well.)

The early attempts to vent the RHR system were unsuccessful partially due to under sized vent lines and the piping system that trapped water to prevent venting of certain portions of the system. Between 0945 and 0956, pressurizer level continued to decrease and the RCS pressure remained constant at about 33 psig.

Between 0956 and 0959, an attempt to start the 12RHR pump was unsuccessful. However, pressurizer level dropped from about 38% to 23% and pressure dropped from 33 psig to 18 psig during the start attempt. Level and pressure remained constant until RCS refill was initiated.

Between 1018 and 1023, operator initiation of gravity fill of the RHR system from the RWST increased suction line pressure and RCS inventory. Venting was accomplished successfully and at 1023 RHR was restored. Level and pressure were stable and constant at 56% and 18 psig, respectively.

2.3 Cause of Event

The root cause of the event was operator error due to inattention to detail in that he unblocked the isolation valve for accumulator 14 instead of the isolation valve for accumulator 13 from the rear panel 1PR4. Several additional factors were identified which contributed to this operator error.

The surveillance procedure used (SP(0)4.0.5-V-SJ-6) did not require specific sign-offs to verify that the correct accumulator isolation valve was unblocked from the rear panel. Interviews with several plant operators indicated that the procedure steps requiring sign-offs received more attention than those that did not. The adequacy of this procedure is discussed in more detail in Section 2.5

Another important contributor to this event was the human engineering deficiency associated with the control room lay out. Specifically, the unblocking switches were arranged in the control room panel in 11, 12, 14, 13 order. When the third accumulator (13) was being set up for discharge,

the operator proceeded to the switch in the third location (14) and actuated it. The licensee had already recognized the layout of those switches to be a human engineering deficiency (HED), and as such, plans to correct that HED during a subsequent phase of the control room modifications.

A third contributing factor was the station policy which permits only reactor operators (RO) to manipulate the controls. In this case, however, a senior reactor operator (SRO) performed that evolution and actuated the wrong switch. Although the SROs are licensed to perform this function, their primary responsibilities are to direct the activities of the ROs, who are more familiar with the details of the control boards.

Prior to this test, the licensee was performing full flow testing of the high head safety injection system. This safety injection system flow testing was delayed for several hours. Since plant conditions satisfied the test requirements for SP(O)4.0.5-V-SJ-6, and the test was scheduled to be performed prior to entering Mode 4, control room supervision elected to perform the accumulator discharge test during this delay. Although ample time appeared to be available to complete the test, interviews with licensee personnel indicated that the test may have been rushed. (There appeared to be no undue pressure placed on the operations staff to complete the test quickly.) This may also have contributed to the operator error.

In summary, although the cause of the event was operator error, several additional factors contributed to the error.

2.4 Reportability of Concerns

The loss of the RHR system occurred at approximately 9:45 a.m. on May 20. 10 CFR 50.72, Section (6)(2)(iii)(B), requires the licensee to notify the NRC within four hours of any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to remove residual heat. This event was not reported as required by that section until about 11:00 a.m. on May 22.

The inspector reviewed the details associated with the licensee's implementation of reportability requirements. The inspector determined that following the event, operations personnel referenced the Event Classification Guide (ECG) to determine event reportability. Tab 17 (Safeguards) was referenced first, which specifically stated that if the RHR system fails to attain/maintain RCS at 200° F, then declare an Alert. Since 200° F was not reached (122 F maximum), that declaration was not applicable. The other section that could have potentially applied was Tab 17 (Technical Specifications). Item J, "Event or condition that alone could have prevented the function of safety structures of systems," was reviewed; however, it was not as specific as 10 CFR 50.72. Although item J contained implementing examples, none appeared to specifically fit the event. Therefore, the licensee did not report the total loss of RHR event.

Followup investigation identified that although the event was not officially reported, the licensee recognized the importance of the event and did notify several organizations, including NRC Region I, later on May 20. It was not until Monday, May 22, that the licensee determined that the event was a 50.72 reportable event. The licensee stated that the ECG was designed to contain all of the necessary information to determine reportability and the operators are not expected to review 10 CFR 50.72 for reportability of an event.

The inspector noted that the licensee was in the process of implementing a major change to the ECG procedure. The revision which was reviewed for approval by the Station Operations Review Committee on May 3, 1989, included specific guidance in several appropriate locations that clearly identified the proper reporting requirement for the May 20 event. However, the revision was not effective prior to the event. The new ECG procedure was subsequently issued and became effective on May 26, 1989.

The ECG procedure was inadequate in that it did not provide the necessary guidance to properly classify the event and report it to the NRC. This is an apparent violation of NRC requirements (50-272/89-17-01).

2.5 Test Procedure Adequacy

The inspector reviewed the procedure and testing requirements associated with this event. Surveillance procedure SP(O)4.0.5-V-SJ-6, "Inservice Testing - Valves - Safety Injection", prescribes the testing process for the accumulator discharge check valves (two series check valves for each of the four accumulators).

ASME Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components", Subsection IWV-3520 (Check Valve Tests) and the licensee's approved Inservice Testing (IST) Program require that the above check valves be full-stroke tested during each cold shutdown. Section XI specifies that the test can be performed with or without flow through the valve. Additionally, IWV-3200 (Valve Replacement, Repair and Maintenance) requires that valves be tested following specified activities to ensure that performance parameters are within acceptable limits.

The above referenced SP(O) was performed on March 31, 1989, to satisfy the licensee's IST Program requirements. During the outage, all eight check valves were modified, and as such were required to be tested following the modification. The licensee performed the SP(O) on May 20 to satisfy the post-modification/ maintenance requirement.

The inspector reviewed the surveillance procedure and found that the licensee performs that test at normal system operating parameters for the accumulators (595.5 to 647 psig pressure and 51 to 65% level). Performing the discharge test at full accumulator pressure and a significantly low RCS pressure resulted in the nitrogen injection and the associated problems of the May 20 event.

The inspector also identified that there were no sign offs for the action steps prescribed by the procedure, which could potentially lead to the omission of steps or performing evolutions out of sequence. The inspector interviewed several operators and found that the operators felt that steps which require their sign off received more attention than those that did not. This may have contributed to the operator error in performing the test. The licensee stated that they recognized that certain procedures did not contain the necessary sign off steps and these procedures were slowly upgraded as a part of an integrated procedure upgrade program. The inspector found, however, that the two-year review was performed for the above referenced SP(O) on December 2, 1988, and no changes were made.

Technical Specification (TS) 6.8.1 requires that written surveillance and test activity procedures shall be established, implemented and maintained. TS 6.8.2 requires that those procedures shall be independently reviewed by a station qualified reviewer (SQR) and approved by the appropriate station department manager prior to implementation. Administrative Procedure No. 32, "Implementing Procedures Program," specifies that the SQR will prepare a safety evaluation for those procedures which involve a significant safety issue (SSI) and the implementing department manager will document the determination as to whether the procedure contains an SSI. If a procedure contains an SSI, then a 10 CFR 50.59 safety evaluation must be completed and Station Operations Review Committee (SORC) review must be performed per TS 6.5.1.6 requirements.

Inspector review of SP(O)4.0.5-V-SJ-6 identified that no SORC review had been performed. Additionally, the yes/no classification for the SSI determination was not checked. The licensee stated that the SSI classification was no, and therefore no SORC review was required. The licensee failed to properly evaluate the safety implications of performing this procedure under specific plant conditions. The failure to perform the appropriate safety review for the surveillance test procedure is a violation of Technical Specification requirements (50-272/89-17-02).

2.6 Abnormal Operating Procedure Adequacy

Following identification of RHR pump problems and the subsequent stoppage of both pumps, the licensee initiated Abnormal Operating Procedure AOP-RHR-1, "Loss of RHR Cooling." Entry conditions that precipitated usage of this procedure included an abnormal change in RHR pumps motor current and the subsequent loss of both RHR pumps.

AOP-RHR-1 usage for the given plant conditions would eventually lead to the establishment of RCS feed and bleed operations. Since incore thermocouple temperatures were rising at a slow rate (~ 1/2° F per minute) other actions were being taken simultaneously with setting up for feed and bleed operations. This included continuing efforts to vent the RHR pumps in an attempt to reestablish RHR flow.

In conjunction with the performance of AOP-RHR-1, personnel were also reviewing AOP-RHR-2, Loss of RHR Cooling - RCS Level Below Pressurizer - EL104." AOP-RHR-2 applies to the loss of RHR cooling during mid-loop operations. Since the RCS level was above the 104 feet level (greater than mid-loop), entry into this procedure was inappropriate. However, as a result of continuing training received for mid-loop operation, shift personnel knew that level in the RCS could be maintained by gravity drain from the refueling water storage tank (RWST) and therefore could be used as a means for possibly filling and venting the RHR system. Operation of valve SJ-69 for gravity draining of the RWST is designated in step 3.8.6 of AOP-RHR-2.

In completing AOP-RHR-1, step 3.13.5, which essentially completed the actions necessary for feed and bleed, with the exception of starting a charging pump, the shift supervisor opened SJ-69. Pump venting efforts were successful at this time and a restart of the RHR pumps subsequently took place, whereupon RCS conditions were returned to normal.

In summary, it was apparent that the established procedures were not adequate for the plant conditions during this event. The licensee identified these deficiencies, and the applicable procedures were being revised. However, operator actions taken during the recovery of this event were considered appropriate for the conditions that existed.

2.7 Adequacy of Training

A review was performed to determine the extent of training received by licensed operators both prior to and after the event. The extent of the training department's involvement during and after this event was also assessed.

As a result of this review, it was determined that previous RCS mid-loop operation training, conducted during the week of April 3, 1989, helped the operators during the attempted recovery of the RHR pumps. It eventually provided a course of action for them to take instead of feed and bleed of RCS as designated in AOR-RHR-1.

Following the event, the operation's department provided informal training to all licensed operators not involved in the event prior to their assuming any watchstanding positions. These briefings included a review of the following:

- Sequence of events
- Inappropriate operator actions
- Inadequacies of AOR-RHR-1 for given plant conditions
- Injection of Nitrogen into RCS

It was not apparent that the training department provided any oversight or assistance to the operations department during the conduct of these briefings. It was determined that the training department did not become aware of the event until three days later. Even after becoming aware, training involve-

ment was minimal. Not until the fifth day following the event, did the training department meet with the operations department to review the sequence of events and formulate desired courses of action in regards to training. These courses of action, both short and long term include the following:

- Develop or revise licensed and non licensed operator training materials to support corrective actions identified by the ongoing investigation of this event.
- Incorporate training on the event in continuing licensed and non licensed training programs.
- Review the event and follow-up investigations with entire shift compliment during segment 1 of the 1989-90 continuing training program.
- Develop and conduct training of various pump failures/cavitation.
- Upgrade the capability of the Salem simulator to provide "hands-on training" of abnormal RHR events.
- Review the design basis and specifications for the ECCS accumulators and their applications.

In summary, it was evident that there was a definite lack of initiative to get the training department involved in the training related to this event. Even though the operations department representatives stated that they felt no need for immediate assistance from the training department, they did not inform the training department of the events shortly after it had occurred. The training department appeared not to be kept current of all operational events regardless of the outcome or severity.

The training department also was not aggressive in offering their assistance and becoming involved once they were informed of this operational event. As such, training personnel were not involved in the investigation that followed the event, and the training department was not kept abreast of the conclusions of the investigation to develop meaningful short term and long term training programs to preclude the reoccurrence of this event.

Licensee management involvement appeared to be lacking in their use of resources available in the training department to effectively investigate plant occurrences and to develop meaningful short and long term training programs.

2.8 Licensee Corrective Actions

The licensee initiated the following short term corrective actions:

1. Training of oncoming licensed shift personnel was conducted as detailed in section 2.6 of this report.

2. Use of the accumulator discharge test procedure, SP(O)4.0.5.V-SJ-6 was discontinued pending reevaluation of testing requirements.

3. Abnormal Operating Procedure AOP-RHR-1, Loss of RHR cooling was revised to incorporate the conditions present in the RCS at the on set of the loss of RHR event, with reactor vessel head installed, RCS vented, and level in pressurizer.

4. AOP-RHR-1 was revised to incorporate use of additional vent paths, including reactor head vents as recommended by Systems Engineering.

5. The Training Center was developing training plans to incorporate the lessons learned from this event.

6. The Unit 1 Emergency Core Cooling System Surveillance test procedure (SP (O) 4.5.2h) was revised to incorporate the enhanced guidance for removing excess RCS inventory. Additionally, Unit 1 and 2 Cold Shutdown to Hot Standby Integrated Operating Procedures (IOP-2), Draining Reactor Refueling Cavity were identified as requiring the same procedural enhancement. Revision to these procedures will be completed prior to June 15, 1989.

7. Flow testing of the remaining accumulator check valves was ordered stopped by the General Manager - Salem Operations, pending initial review of the event, SORC approval and GM - Salem Operations approval to resume flow testing.

8. Evaluation of the event from a systems engineering/analysis perspective, was conducted.

9. Notified the industry through the Nuclear Network.

10. Submitted Operating Experience Report to INPO for Industry Experience Information.

11. Event Classification Guide (ECG) was revised and issued on May 26, 1989. Additional review of the new revision will be conducted by licensing personnel.

The licensee's planned long term corrective actions are:

1. Accumulator block out switch reconfiguration to incorporate previously identified Control Room Human Factors deficiencies will be completed in accordance with the Control Room redesign schedule (i.e., next refueling outage).

2. Develop specific training for this event to:

   a. Discuss Sequence of Events

b. Discuss root cause of identified inappropriate actions taken during event.

c. Review the design basis and specifications for the ECCS accumulators and their application.

d. Review revised procedures:

1. AOP-RHR-1
2. AOP-RHR-2
3. IOP-2
4. SP(0)4.0.5.V-SJ-6
5. Other applicable procedure changes

This will be completed by September 1989 and be incorporated into the continuing training process.

3. Review the procedure weaknesses of SP(0)4.0.5.V-SJ-6 and AOP-RHR-1 with Station Procedure Writers by July 1, 1989.

4. Conduct an independent investigation of the event and submit the results to the Vice President and Chief Nuclear Officer by June 16, 1989.

5. Develop or revise the licensed and non licensed operator training materials to support the corrective actions identified by the ongoing and independent investigation of the event.

6. Develop and conduct improved training with regard to various pump failure/cavitation conditions.

7. Review the need to upgrade the capability of the Salem simulator to provide "hands-on training" of abnormal RHR events.

8. Evaluate the need for improved venting capabilities on the RHR piping.

9. Evaluate the need to provide physical in plant training and/or detailed description in procedures of selected valves and other components important for maintaining core inventory.

10. Evaluate IST testing to determine the best test method for the accumulator check valves. The guidance of Generic Letter 89-04 will be used in this effort.

11. Evaluate the use of SPDS for shutdown operations and identify potential areas of enhancement.

3.0 Conclusion

The NRC inspectors concluded that the licensee's engineering evaluation adequately addressed the system responses during this event. However, the licensee did not assess the event from a system response perspective until NRC personnel got involved in the event follow-up. Except for the initial operator error and a questionable decision to drain RCS upon high pressurizer level, the operator actions demonstrated excellent skills and knowledge of the system. Specifically, the operators used the knowledge gained from mid-loop operation training while venting the RHS system during this event.

Procedure deficiencies played a significant role during this event. The surveillance test procedure for testing of the check valve did not appear to alert the operators about nitrogen intrusion. The abnormal operating procedures did not guide the operators to declare an alert when both RHR pumps were lost. The event classification guidelines were not adequate to inform the operator that a 10 CFR 50.72 reportable condition existed when the facility lost both RHR pumps.

The above procedural deficiencies constitute a violation of Technical Specification 6.8.1. The inspectors found the licensee's short and long term corrective actions effective in addressing the circumstances that led to this event. The use of resources available in the licensee's training department was not apparent during licensee's investigation of this event.

With the exception of the findings discussed in this report, the inspectors found the licensee's response to this event, engineering analysis and short and long term corrective actions to be effective in mitigating the consequences of this event and precluding this event from occurring in the future.

4.0 Exit Meeting

The findings of this inspection were discussed with the licensee representatives (denoted in Paragraph 1) at the exit interview on May 26, 1989. No written material was provided to the licensee by the inspectors. The licensee did not indicate that proprietary information was involved within the scope of this inspection.

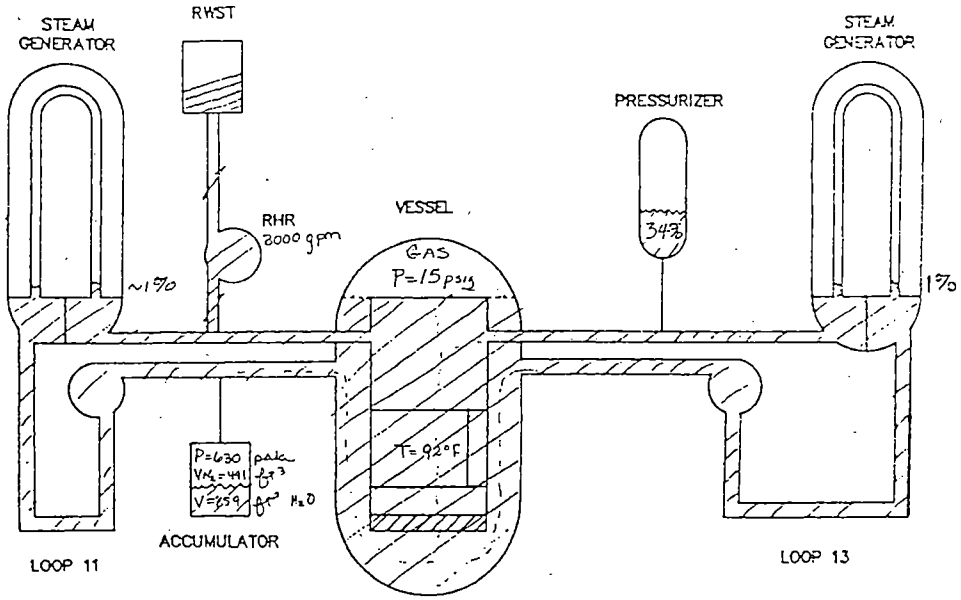

FIGURE 1

TIME 9:25 am

RCS VOLUME: 11,905 CFT
AIR IN RCS: 4,086 CFT
NITROGEN IN RCS: 0 CFT

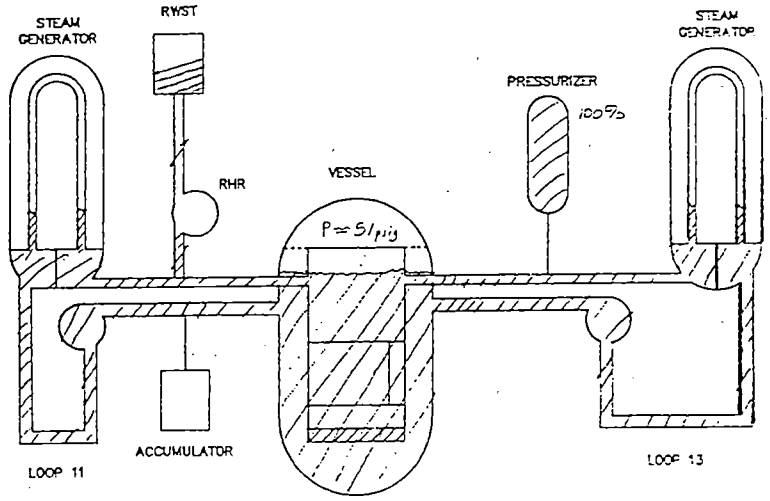

FIGURE 2

TIME 9:27 am

NITROGEN IN RCS: 2,307 CFT

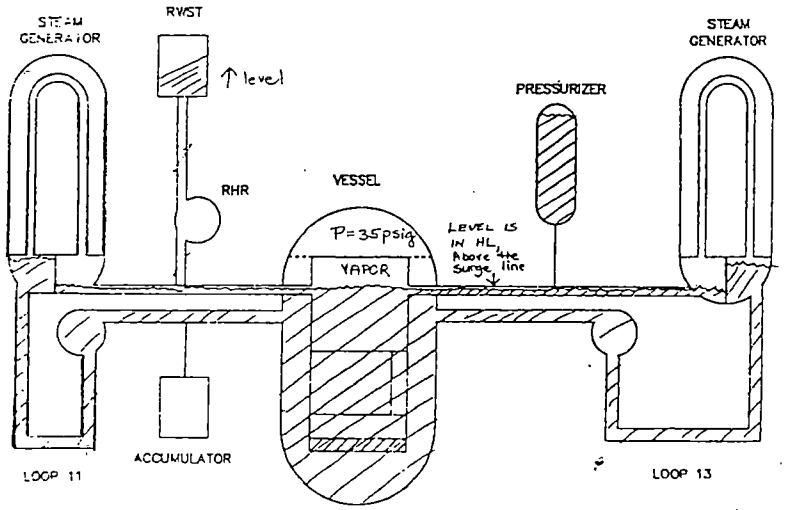

FIGURE 3

TIME 9:35 am

RHR PUMP IS GAS BOUND

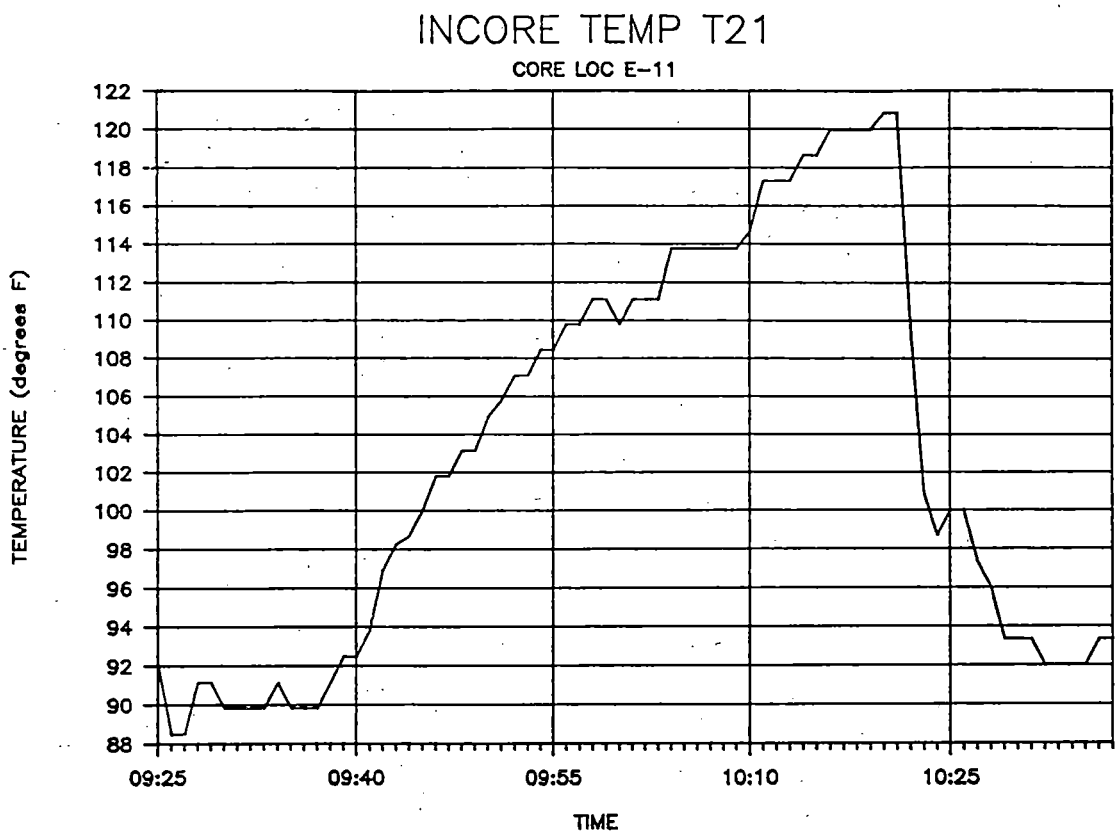

FIGURE 4

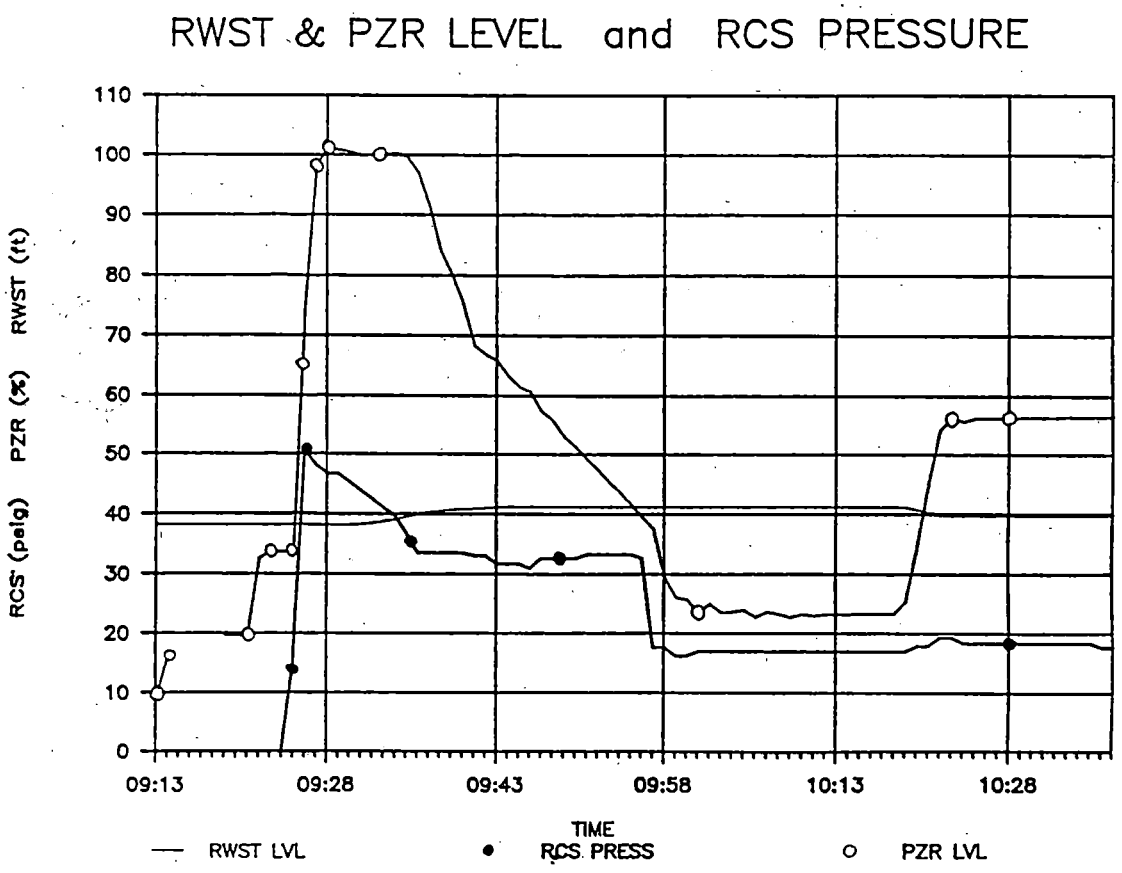

FIGURE 5