U. S. NUCLEAR REGULATORY COMMISSION

REGION I

050354-860611
050354-860618
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050354-860703
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050354-860707

Report No. 50-354/86-36

Docket 50-354

License NPF-57

Licensee: Public Service Electric and Gas Company

Facility: Hope Creek Generating Station

Conducted: July 15, 1986 - August 11, 1986

Inspectors: R. W. Borchardt, Senior Resident Inspector
D. K. Allsopp, Resident Inspector
R. J. Summers, Project Engineer

Approved: R. J. Summers for 9/4/86
L. Norrholm, Chief, Projects Section 2B Date

Inspection Summary:
Inspection on July 15, 1986 - August 11, 1986 (Inspection Report Number 50-354/86-36)

Areas Inspected: Routine onsite resident inspection of the following areas: followup on outstanding inspection items, operational safety verification, surveillance testing, maintenance activities, engineered safety feature system walkdown, licensee event report followup, licensee identified violation, and a management meeting summary. This inspection involved 204 hours by the inspectors.

Results: Although no violations were cited in this report, paragraphs 5 and 8 discuss concerns that warrant prompt attention. As discussed in paragraph 5, a safety related system (Service Water) was declared operable without resolution of an outstanding Deficiency Report (DR). This DR questioned the structural integrity of a portion of the Service Water (SW) system and should have been dispositioned prior to declaring the SW system operable. This practice was in violation of the station Administrative Procedures; however, because the station Quality Assurance Organization

had recently identified a nearly identical situation the NRC will evaluate the station's corrective actions prior to making a decision on possible enforcement. Paragraph 8 documents a number of self identified violations for which corrective actions have already been taken. While the self identification of these violations is seen as a positive indicator it also makes clear the need for an increased attention to detail in all phases of plant operations. Because the violations were promptly identified and effective corrective actions taken in a timely manner, no NRC enforcement actions will be taken.

DETAILS

1. Persons Contacted

Within this report period, interviews and discussions were conducted with members of the licensee management and staff and various contractor personnel as necessary to support inspection activity.

2. Followup on Outstanding Inspection Items

2.1 Inspector Follow Items

(Closed) Inspector Follow Item (85-64-05); Reactor Core Isolation Cooling (RCIC) Pump Functional Test and Flow Verification. During the Technical Specification (TS) inspection conducted prior to plant licensing it was identified that the RCIC inservice test did not adequately address all of the TS required conditions. The inspector has subsequently reviewed revisions to OP-IS.BD-001 "Reactor Core Isolation Cooling Pump - Inservice Test" and OP-IS.BJ-001 "HPCI Main and Booster Pump Set - Inservice Test" and verified that the required test conditions are specified in the body of these procedures. The inspector has no further questions at this time and this item is closed.

(Closed) Inspector Follow Item (86-02-01); Inservice Testing Acceptance Criteria. The inspector reviewed various inservice test procedures for safety related pumps and verified that the acceptance criteria is now incorporated into the body of the procedure. This ensures that the acceptance criteria and alert ranges will receive the same level of review as all other surveillance tests and the procedure will be controlled by the licensee's controlled distribution system. The inspector has no further questions at this time and this item is closed.

(Closed) Inspector Follow Item (86-20-03); High Pressure Coolant Injection (HPCI) Surveillance Tests. During a previous inspection the inspector identified two concerns relating to the adequacy of HPCI system surveillance tests. Surveillance Test OP-ST.BJ-001(Q) - Rev. 1 "HPCI System Piping and Flow Path Verification" was reviewed to verify that both injection paths (feedwater and core spray) were now properly vented and filled. Revision 1 to this ST corrected the inspector's concern relating to adequacy of the HPCI valve lineup and prevention of water hammer events. The inspector also reviewed OP-SO.BJ-001(Q) - Rev. 2 "High Pressure Coolant Injection System Operation" to verify that both vent paths were properly identified. Proper operation of air operated valve F025 is now verified in procedure OP-ST.BJ-002 - Rev. 2 "HPCI System Functional Test (Low Pressure) 18 Month". The inspector has no further questions at this time and this item is closed.

(Closed) Inspector Follow Item (86-20-06); Logic Power Monitor Surveillance Test. During an inspection of surveillance tests (ST) prior to operating license issuance the inspector found that a number of ECCS logic power monitor circuits were not tested. The licensee wrote and performed ST OP-FT.ZZ-002 "Logic and Inverter Power Monitor Test" to ensure the proper operation of the logic power monitors for ADS, Core Spray, RHR, HPCI and RCIC. The inspector reviewed the ST and has no further questions at this time.

(Closed) Inspector Follow Item (86-26-02); Review QC Surveillance Report. QC Surveillance report HQC-86-628 documents a number of deficiencies identified by the inspector during observation of control rod drive maintenance (CRDM) work during May 1986. The inspector reviewed this QC report and the licensee's corrective actions and found them to be acceptable. In addition, QC report 86-155 was reviewed which documented the QC surveillance of CRDM work when it was recommenced. The activities were found to be acceptable. This item is closed.

2.2 IE Bulletins

(Closed) IE Bulletin (86-BU-02); Static "O" Ring Differential Pressure Switches. The purpose of this bulletin was to request the licensee to determine whether or not they have Series 102 or 103 differential pressure switches supplied by Static "O" Ring (SOR) Incorporated installed as electrical equipment important to safety. In a response dated July 30, 1986, the licensee documented that Hope Creek does not use any of the subject switches in important to safety applications. The inspector held discussions with system engineers and conducted independent plant tours to verify that SOR differential pressure switches are not used. This bulletin is closed.

3. Operational Safety Verification

3.1 Documents Reviewed

- Selected Operator's Logs
- Senior Shift Supervisor's Log
- Jumper Log
- Radioactive Waste Release Permits (liquid & gaseous)
- Selected Radiation Work Permits (RWP)
- Selected Chemistry Logs
- Selected Tagouts
- Health Physics Watch Log

3.2 The inspectors periodically toured the plant during regular and backshift periods. These tours included the control room, Reactor, Auxiliary, Turbine and Service Water buildings, and the drywell (when access is possible). During the inspection, discussions were held with operators, technicians (HP & I&C),

mechanics, supervisors, and plant management. The purpose of the inspection was to affirm the licensee's commitments and compliance with 10 CFR, Technical Specifications, and Station Procedures.

(1) On a daily basis, particular attention was directed to the following areas:

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

(2) On a weekly basis, the inspectors confirmed the operability of selected ESF trains by:

- Verifying that accessible valves in the flow path were in the correct positions;
- Verifying that power supplies and breakers were in the correct positions;
- Visually inspecting major components for leakage, lubrication, vibration, cooling water supply, and general operating conditions; and,
- Visually inspecting instrumentation, where possible, for proper operability.

(3) On a biweekly basis, the inspectors:

- Verified the correct application of a tagout to a safety-related system;
- Observed a shift turnover;
- Reviewed the sampling program including the liquid and gaseous effluents;

- Verified that radiation protection and controls were properly established;

- Verified that the physical security plan was being implemented;

- Reviewed licensee-identified problem areas; and,

- Verified selected portions of containment isolation lineup.

3.3 Inspector Comments/Findings:

The unit entered this report period in Mode 2 with the reactor critical for power ascension heatup phase testing.

During the period from July 15 to July 20, the unit experienced four separate automatic initiations of the High Pressure Coolant Injection (HPCI) system. During each of the events, the HPCI turbine was tripped before any water was injected into the reactor vessel and all systems responded properly for the plant conditions in effect. A review of plant conditions prior to, and after the actuations showed that reactor vessel water level remained within the normal range and that HPCI should not have received an actuation signal. The licensee's investigation and a subsequent test conducted on July 20, established the most probable cause for three of these spurious actuations to be workers in the drywell bumping into reactor vessel level sensing lines. For the actuation on July 16, the cause was determined to be an Instrument and Controls technician valving error. In an effort to prevent further spurious actuations, the licensee placed more stringent controls on access into the drywell and reinforced the importance of proper valve operations to I&C technicians.

At 1:37 a.m. on July 19, the reactor scrammed from approximately 0.5% power due to an operator error in the manipulation of the "B" and "G" Intermediate Range Monitor (IRM) range switches. As reactor power was being increased the "B" and "G" IRMs were simultaneously downranged instead of upranged causing the two IRM channels to go upscale and trip the A and B Reactor Protection System (RPS) scram channels. The plant was placed in a stable condition and a post scram review conducted. The reactor was taken critical at 5:51 p.m. on July 19, for continuation of the low power test program.

On July 21, a Commission meeting was held to discuss and vote on a full power license for Hope Creek. The Commissioners voted 4 to 0 in favor for authorizing a full power license. On July 24, NRC - Region I met with the licensee to discuss the corrective action program for the spurious ESF Actuations and the license was issued on July 25. Additional details on the July 24 meeting can be found in paragraph 9 of this report.

At 8:20 p.m. on July 25, a reactor scram occurred from 3% power due to reactor vessel low water level. Surveillance testing was in progress on the turbine stop and control valves when an operator erroneously shut the valves to start turbine chest warming. This resulted in all bypass valves opening and a reactor high water level due to swell which tripped the two operating feed pumps. Feedwater was not restored before the reactor scrammed on low level. All systems responded normally to the scram. Following a SORC review of the event, the reactor was made critical at 7:48 a.m. on July 26.

At 5:28 p.m. on July 29, the reactor scrammed while troubleshooting the -22 volt DC portion of the Electro Hydraulic Control (EHC) logic system. During troubleshooting, the -22 volt DC supply was lost and all bypass valves went full open causing reactor vessel level swell. All feed pumps tripped due to the reactor vessel high water level. The pumps were not restarted prior to receiving a low water level reactor scram. Prior to the scram, reactor power was at 6%, preparing for main turbine synchronization with the grid. The licensee commenced a reactor startup at 3:15 a.m. on July 31, and terminated startup at 4:45 a.m. when the rod position indication system (RPIS) failed. The reactor was maintained subcritical until RPIS troubleshooting was complete and the reactor taken critical later that day.

At 5:34 a.m. on August 4, an erroneous level-1 and level-2 channel "A" LOCA signal was received when an I&C technician improperly checked a valve position causing a pressure spike to the "A" instrument rack. All equipment responded normally for plant conditions (Mode 4, reactor temperature 140 degrees F).

At 10:25 p.m. on August 5, a channel "A" primary containment isolation system (PCIS) actuation occurred which tripped reactor building ventilation fans, closed valves in the RHR and reactor water cleanup systems and started fans in the Filtration, Recirculation Ventilation System (FRVS). A low reactor vessel level "seal in" signal was generated earlier in the day during backfilling of the "A" level instrument rack. At 10:25 p.m. the "A" manual initiation pushbutton was depressed as part of an I&C surveillance test. These two signals combined to cause the channel "A" PCIS actuation. A contributing factor to this event is the fact that there is no indication easily available to the control room operator that one of the PCIS actuating signals is sealed in. Although a reactor vessel low level condition did not exist at the time of the isolation, the signal was still sealed in from earlier in the day. The station has initiated a Design Change Request to evaluate and possibly install an indicating light to alert the operator that a sealed in actuation signal is present. The inspector will follow the resolution of this problem (86-36-01).

At 11:45 a.m. on August 8, the licensee declared an unusual event when it was discovered that the reactor building to torus vacuum breaker butterfly isolation valves (HV-5029 and HV-5031) were inoperable and would have prevented the vacuum breakers from fulfilling their safety function. The plant was shutdown and separate investigations by the plant staff and the offsite safety review committee commenced. It was determined that the differential pressure transmitters were connected backwards, such that the isolation valves would close as a vacuum was created in the torus instead of open as required. This incident will be the subject of NRC special inspection report 50-354/86-41.

3.4 The inspector reviewed selected portions of the fire protection program which were incorporated into the Final Safety Analysis Report (FSAR) and deleted from Technical Specifications on July 25, 1986. The inspector toured the joint Salem and Hope Creek fire station and discussed procedure implementation with the senior fire house supervisor. The fire station appears adequately equipped and well organized. Procedure implementation was found to be consistent with FSAR requirements.

No violations were identified.

4. Surveillance Testing

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

The following surveillances were reviewed, with portions witnessed by the inspector:

- IC-TR.SB-007(Q) Time Response Test Reactor Protection System - Division 3 Channel C71-N006D & C71-N006C Turbine Stop Valve Closure RPS Trip EOC - RPT System B Trip
- OP-ST-SN-001(Q) ADS/SRV Manual Operational Test - 18 Month
- OP-AB.ZZ-121(Q) Failed Open SRV

- OP-ST.GS-004(Q) Suppression Chamber/Drywell Vacuum Breaker Operational Test
- IC.FT-SE-011 IRM Channel G Functional Test
- IC-TE.SE-002 NI System Division 3, Channel C APRM Temporary Scram Clamp Adjustment
- IC-TR.SE-007 APRM-C Time Response Test

No violations were identified.

5. Maintenance Activities

During this inspection period the inspector observed selected maintenance activities on safety related equipment to ascertain that these activities were conducted in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards.

Portions of the following activities were observed by the inspector:

Work Order	Description
86-07-23-171-5	"A" Safety Auxiliary Cooling System Pipe Repair

On July 28, 1986, a through wall leak was identified on the service water outlet pipe from the A-1 Station Auxiliaries Cooling Water System (SACS) Heat Exchanger. A work order was established to inspect and repair the pipe. Based on examination the licensee found that the protective lining (a phenolic coating) had been eroded away and that the base metal of the pipe had experienced a corrosion/erosion attack. The affected area appeared to be limited to a small region of the pipe wall where the service water flow was directed by a flow balancing, throttling valve on the outlet of the heat exchanger. The licensee effected a temporary repair by use of a welded external patch over the affected area. This repair was to permit operation of the system for approximately 1 to 2 weeks until the station entered an outage following the completion of the low power testing plateau.

Based upon the extent of the damage to the pipe, the licensee decided to examine the outlet legs of the "B-1" and "B-2" SACS heat exchangers. Conditions similar to, but not as extensive as on A-1 were found. Damage to the valve seat, phenolic coating and pipe wall were all noted and Deficiency Reports were written on the identified nonconforming conditions. The "B" SACS heat exchanger was placed in service (and declared operable) without any repairs at the time, since the damage was not as extensive as determined by the visual exams.

The inspector questioned the determination to declare the system operable without resolution of the DR's. No evaluation or tests of the structural integrity of the pipe had been conducted prior to returning it to service. This type of evaluation appeared to be a requirement of Station Administrative Procedure (AP.ZZ-020). The inspector discussed this finding with the station QA engineer to see if similar findings had been noted by QA. At the time, a Corrective Action Report (CAR) was in preparation which discussed a similar occurrence where the HPCI system was declared operable with a DR still unresolved due to overpressurizing the discharge piping during testing. CAR-HS-86-020-0 was issued (after including the service water pipe issue) to the station on July 30, 1986.

During the outage conducted August 1986, repairs were made to the affected service water pipe. This included building up the wall of the pipe with a weld overlay and restoring a protective lining to the area by applying Belzona epoxy to the pipe. Based on previous experience the licensee has determined that Belzona epoxy is very resistant to the erosion effects of the service water. The inspector will follow the licensee's long term corrective actions for the throttling valves and also the response to the CAR to prevent future occurrences (86-36-02).

No violations were cited.

6. Engineered Safety Feature (ESF) System Walkdown

The inspectors verified the operability of the selected ESF system by performing a walkdown of accessible portions of the system to confirm that system lineup procedures match plant drawings and the as-built configuration. This ESF system walkdown was also conducted to identify equipment conditions that might degrade performance, to determine that instrumentation is calibrated and functioning, and to verify that valves are properly positioned and locked as appropriate. The "A" Loop of Low Pressure Coolant Injection (Residual Heat Removal) was inspected.

Prior to the inspector's system walkdown, the licensee identified flange leaks on the Residual Heat Removal (RHR) system on two separate occasions. An investigation determined the flange bolt torque settings on the leaking flanges were significantly below PSE&G's maintenance program requirements. The resident inspector asked the system engineer if there was a generic problem and if so, what was being done to correct the problem. After an investigation, the system engineer concluded that the architect engineer (Bechtel) had no torque specifications for flanges on systems rated under 600 psig (this includes RHR). To verify piping integrity on these systems prior to turnover from Bechtel to PSE&G, a hydrostatic test was performed in accordance with Bechtel Test Specification 10855-P-590(Q). Through established leakage criteria, the hydrostatic test was utilized to verify system integrity. PSE&G has a well defined maintenance program which includes torque specification for all bolts, nuts, and fasteners regardless of system rated pressure. The system engineer initiated work orders to check torque specifications on all flanges in core spray and RHR piping greater than one inch diameter. The licensee determined that torque settings varied widely on any given flange and that the average as-found torque was roughly one-half the torque required by PSE&G's maintenance program.

No violations were identified.

7. Licensee Event Report Followup

The licensee submitted the following event reports during the inspection period. All of the reports were reviewed for accuracy and timely submission. Certain designated reports as indicated by an asterisk, were followed up by the inspector for corrective action implementation.

* LER 86-18 Failure of Service Water Strainers

LER 86-29 Automatic Start of "B" Control Area Chiller

LER 86-30 Automatic Start of "B" Control Area Ventilation Train

* LER 86-31 Reactor Scram Due to Personnel Error in Ranging IRMs

* LER 86-32 Initiation of Manual Scram for Troubleshooting of Reactor Manual Control System

* LER 86-33 Inadvertent "B" Channel LOCA Signals During Instrument Calibration Performance

* LER 86-35 Reactor Scram Signal Originating From the Neutron Monitoring System

LER 86-36 Isolation of the "A" Control Room Ventilation Unit Due to Radiation Monitor Upscale Trip

LER 86-18 describes the failure of the "A" and "C" station service water pump discharge strainers due to a loss of the self-cleaning mechanism. Insufficient clearance between the port adjustment shoe and the strainer resulted in the port adjustment shoe striking the strainer and caused binding of the self-cleaning mechanism. This binding resulted in a loss of backwash capability and a high differential pressure across the strainer. The root cause has been determined to be a mechanical failure of the strainer element due to a design deficiency of the clearance between the port adjustment shoe and the strainer element. The licensee's corrective action included replacement of both strainer elements and increasing the clearance between the adjustment shoe and the strainer element per the manufacturer's recommendation.

LER 86-31 describes a reactor scram at 1:12 p.m. on June 29, 1986, as a result of an upscale trip on the "D" Intermediate Range Monitor (IRM). The upscale trip occurred as the control operator ranged down IRM "D" from range 2 to range 1 with an IRM reading of 38 on range 2. The "shorting links" were removed in support of shutdown margin demonstration and thus a single IRM trip resulted in a full scram. The licensee counselled the control room operator on the need to carefully review indications and will review the incident with the Nuclear Training Center for inclusion in appropriate training programs.

LER 86-32 describes a manual scram initiated on June 30, to troubleshoot Reactor Manual Control System (RMCS). The reactor was manually scrammed due to the normal shutdown method (control rod insertion) being precluded by a malfunction of the RMCS. Station I&C technicians troubleshot the system while the plant remained in operational Mode 2, but were unable to repair the system. When all avenues for repair available with the unit operating were exhausted, a manual scram was inserted to complete RMCS repairs. The control rods were always "trippable", however, normal rod movement was prohibited due to a faulty transmitter card in the RMCS. The licensee replaced the faulty transmitter card and verified proper operation of RMCS. The inspector has no further questions at this time.

LER 86-33 details two separate actuations of "B" Channel Loss of Coolant Accident (LOCA) logic due to incorrectly returning a level instrument to service. In both of the actuations I&C technicians were returning post accident monitoring level transmitter BB-LT-3682 B to service following calibration activities. Although this transmitter is not a Technical Specification surveillance related instrument, it shares common variable and reference sensing lines with a number of ECCS level transmitters. Also, since this transmitter is not part of the ESF protection system, it was being calibrated using a general vice specific procedure and performed by technicians who had not received the specific surveillance training for Technical Specification Surveillance Tests. The root cause has been identified as personnel error on the part of the I&C technician in performance of valving, in conjunction with a procedural inadequacy regarding the type of procedure that should be used. The licensee's corrective action include identifying and treating all non-surveillance instruments which interface with ECCS and ESF instrumentation as if they were surveillance equipment.

LER 86-35 describes a reactor scram which occurred on July 4, 1986. A half scram was manually inserted prior to the event to comply with an action statement associated with inoperable reactor protection system instrumentation. The scram occurred when a concurrent half scram signal was generated from average power range monitor channel "E" due to a momentary upscale spike of local power range monitor (LPRM) 1C-24-57. The I&C department has determined that the momentary spike was spurious and of unknown origin. The licensee could find no equipment malfunction and the event has not recurred.

8. Licensee Identified Violations

During this report period the licensee identified four instances where the requirements of Technical Specification (TS) were not satisfied. The licensee's findings are documented in licensee generated incident reports and are summarized below.

Incident Report No.	Event Date	Description
86-156	8/1/86	Reactor sample valve time response test not performed in accordance with TS 3.3.2.
86-159	8/3/86	The Safety Auxiliary Cooling System (SACS) to Turbine Auxiliary Cooling System (TACS) isolation valves were found to be inoperable due to shut hydraulic control valves and removed control power fuses. It could not be immediately determined how long SACS had been inoperable.
86-164	8/8/86	Failure to enter the appropriate TS Action Statement after exceeding the allowable 2 hour period for a reactor pressure instrument channel calibration.
86-165	8/8/86	Failure to satisfy TS Action Statement 3.3.7.9 while various ventilation radiation monitors were inoperable

Because the licensee promptly identified the above discrepancies and then took the appropriate corrective and preventive measures, no enforcement action is appropriate in accordance with 10 CFR 2, Appendix C. However, these instances do highlight the need for additional attention to detail in all aspects of plant operations.

9. Management Meeting

On July 24, 1986, a meeting was held between Public Service Electric and Gas Company and the NRC Region I staff in King of Prussia, Pennsylvania. The purpose of the meeting was for PSE&G to present their short term and long term corrective action programs to prevent numerous unexplained spurious ESF actuations. The licensee discussed each of the following areas:

- Summary of all previous ESF actuations since Hope Creek received a low power license including type of actuation, root cause, and corrective action;
- Comparison of Hope Creek's ESF instrumentation, I&C training, and ESF-Related problems to Limerick and Shoreham;
- Implementation schedule for corrective action program including interface with test schedule and outage activities.

The Region I staff was satisfied with PSE&G's corrective actions regarding the ESF actuations and a full power license was issued on July 25, 1986. The list of attendees and a copy of all handouts provided by PSE&G during the meeting are provided as enclosure (1) to this report.

10. Exit Interview

The inspectors met with licensee and contractor personnel periodically and at the end of the inspection report to summarize the scope and findings of their inspection activities. Written material was not provided to the licensee during the exit.

Based on Region I review and discussions with the licensee, it was determined that this report does not contain information subject to 10 CFR 2 restrictions.

Enclosure 1

July 24, 1986 Meeting Between PSE&G and NRC Region I

List of Attendees

Name	Title	Organization
T. Murley	Regional Administrator	NRC Region I
R. Starostecki	Director, Division of Reactor Projects	NRC Region I
W. Johnston	Deputy Director, Division of Reactor Safety	NRC Region I
S. Collins	Chief, Reactor Projects Branch 2	NRC Region I
L. Bettenhausen	Chief, Operations Branch, DRS	NRC Region I
L. Norrholm	Chief, Reactor Projects Section 2B	NRC Region I
P. Eselgroth	Chief, Test Programs Section	NRC Region I
D. Allsopp	Resident Inspector, Hope Creek	NRC Region I
C. A. McNeill	Vice President - Nuclear	PSE&G
S. LaBruna	Assistant General Manager - Hope Creek	PSE&G
B. A. Preston	Manager - Licensing & Regulation	PSE&G
A. Giordano	Nuclear System I&C Engineer	PSE&G
P. Opsal	Senior Staff Engineer	PSE&G/System Engineer
G. Peet	Lead I&C System Engineer	PSE&G/System
G. Tenenbaum	Principal Engineer	PSE&G

NRC REGION I/PSE&G ESF MEETING
THURSDAY, JULY 24, 1986
AGENDA

I. INTRODUCTION

II. SUMMARY OF PREVIOUS ESF ACTUATIONS

III. COMPARISONS TO LIMERICK & SHOREHAM

III. SHORT TERM/LONG TERM PROGRAM

IV. TEST SCHEDULE & OUTAGE ACTIVITIES

V. SUMMARY/CONCLUSION

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LOCA - KNOWN CAUSE

IR/LER NO.	TYPE OF ACTUATION	ROOT CAUSE	CORRECTIVE ACTION
86-058/86-015 (05/06/86)	A Channel LOCA: A Diesel Generator start and A ECCS start...no injection since Rx pressure was greater than the low pressure setpoint.	Instrument root valve cut in too quickly (pressure spike) subject valve and similar valves had not been aligned properly.	Performed valve lineup, approved valve lineup program valves being numbered and included in TRIS program.
86-069/86-020 (05/15/86)	D Channel LOCA: D Diesel Generator start and ECCS initiation signal.(Pumps OOS)	I&C Testing induced pressure transient on D channel	See LOCA Task Force Recommendations.
86-071/86-021 (05/15/86)	D Channel LOCA: D ECCS start...no injection since Rx pressure was greater than the low pressure setpoint. D Diesel was tagged OOS, (no start).	Improper instrument cut-in by I&C technician.	I&C Technician training and LOCA Task Force Recommendations
86-078/86-024 (05/25/86)	D Channel LOCA: D ECCS start, Injection valves tagged shut, D Diesel tagged OOS.	Improper instrument venting on cut-in by technician.	I&C Procedure revised.
86-110/ (07/03/86)	B Channel LOCA: B Diesel start, B ECCS start. 6000 gals injected to Rx.	Improper instrument cut-in by I&C technician on one channel caused pressure spike on LOCA channel.	Identified all instruments which share reference/variable leg with LOCA/RPS instrument and preparing specific procedures for such instruments.
86-111/ (07/03/86)	B Channel LOCA: B Diesel start, B ECCS start, 1000 gals injected.	Same as 86-110.	Same as 86-110.
86-136/ (07/15/86)	C Channel LOCA: HPCI start, no injection.	Instrument cut-in to quickly by I&C technician.	See LOCA Task Force [illegible]
86-041/86-007 (04/20/86)	B Channel LOCA: B Diesel start, B ECCS actuation signal, pumps tagged out, RRCS ARI SCRAM	Root cause initially unknown... Task Force established to investigate the events. Review of design drawings and plant installations was made, as well as inplant testing and monitoring. Events attributed to a combination of procedural problems, air in instrument lines, and control of instrument racks and valves.	ACTIONS TAKEN/RECOMMENDED: ° Blowback instrument lines ° ID tags on instruments ° Quick disconnects on LOCA/ECCS instruments ° Review events with I&C Technicians ° Upgrade procedures ° Include valves in status log ° Install cages around instrument racks
86-048/86-010 (04/26/86)	A Channel LOCA: A Diesel start, A ECCS actuation signal, pumps tagged out, RRCS ARI SCRAM.		
86-057/86-014 (05/06/86)	A Channel LOCA: A Diesel start, A ECCS actuation signal, pumps tagged out.		
86-064/86-019 and 86-065/86-019 (05/13/86)	D Channel LOCA: D Diesel start, D ECCS actuation signal, pumps tagged out... TWO INCIDENTS ON SAME LER		

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IR/LER NO.	TYPE OF ACTUATION	ROOT CAUSE	CORRECTIVE ACTION
86-131/ (07/14/86)	A Channel LOCA: A Diesel Generator Start and A ECCS start...5200 gals injected	Air in instrument lines	Latest Task Force recommendation
86-136 (07/15/86)	C Channel LOCA: HPCI start no injection	Worker stepped on instrument sensing line causing spike	Latest Task Force recommendation
86-138 (07/15/86)	C Channel LOCA: HPCI start no injection		
86-143/ (07/20/86)	C Channel LOCA: HPCI start no injection		

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RPS SIGNALS

IR/LER NO.	TYPE OF ACTUATION	ROOT CAUSE	CORRECTIVE ACTION
86-037/86-003 (04/15/86)	SCRAM SIGNAL: Neutron Monitoring System, (no rods withdrawn)	I&C Technician bumped IRM signal cable causing spike.	I&C Technician training and design changes to protect cables.
86-038/86-004 (04/16/86)	SCRAM SIGNAL: Neutron Monitoring System, (no rods wiothdrawn)	Faulty gain switch on LPRM.	Replaced and calibrated LPRM auxiliary card.
86-047/86-009 (04/25/86)	SCRAM SIGNAL: same as 86-037/86-003.	---	---
86-076/86-023 (05/19/86)	SCRAM SIGNAL: B Channel low Rx level*.. with A Channel in trip (APRM testing)	Improper valving in of transmitter on B Level Channel.	See LOCA Task Force Recommendations.
	* This is categorized as a LOCA signal as well		

COMPARISONS WITH OTHER BWR PLANTS

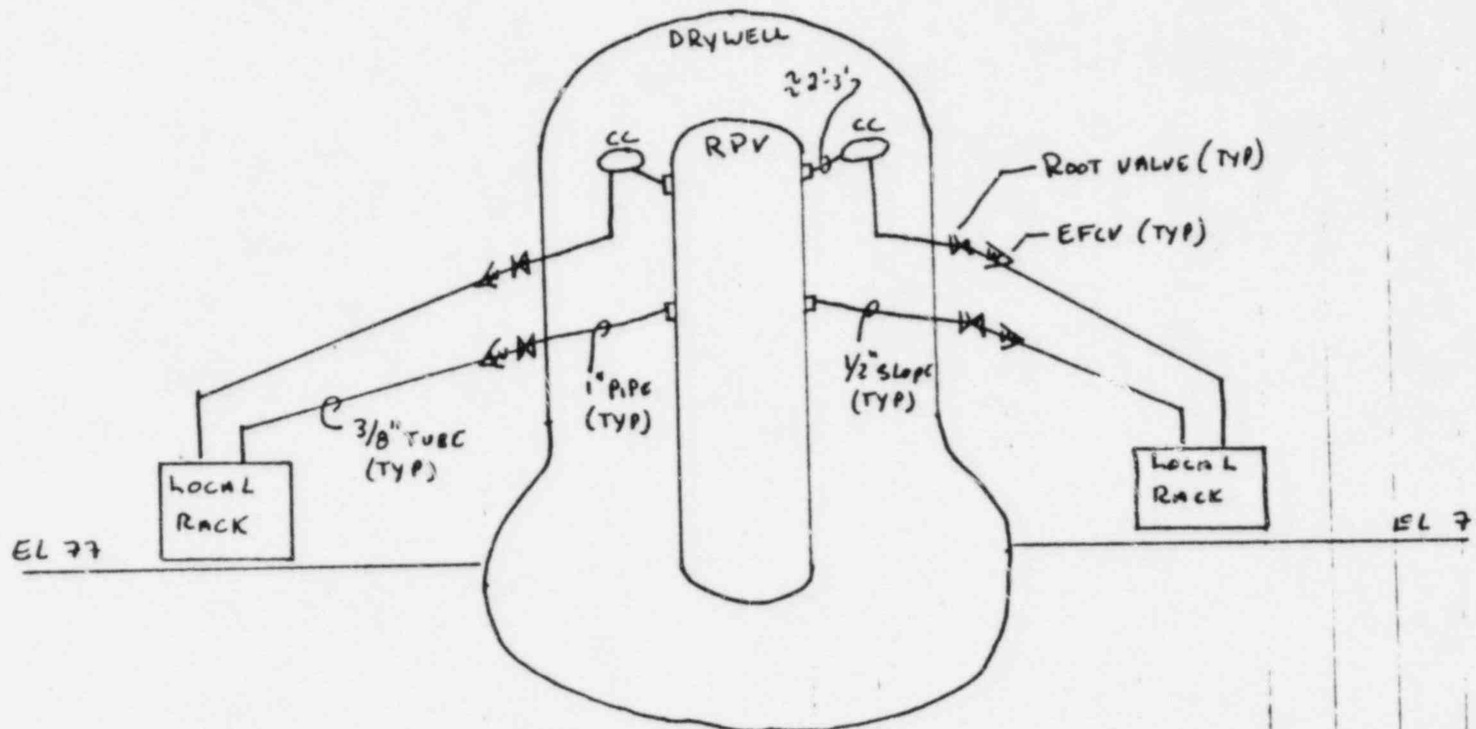
	HOPE CREEK	LIMERICK	SHOREHAM	COMMENTS
Air in the Line Problems	YES Blow Back Lines (As Needed)	YES ***Blow Back Lines Each Time Down**	YES Blow Back Lines (As Needed)	
Type of Plant/AE	BWR/Bechtel	BWR/Bechtel	BWR/S&W	
RFI/EMI Problems (At the Process Instrumentation)	NO	NO	NO	
Sloping GE Instr.	1/2" Some Violations	1/2" Some Violations	1/4" Some Violations	
Ref/Varible Legs	4/4	4/2	2/2	
Condensate Chambers	2" Dia. approx. 3' from vessel, good slope. Free moving.	2" Dia. approx. 3' vessel, good slope. Free moving	2" Dia. approx. 14' from vessel, poor slope was corrected. Free moving	
Insulation of Sensing Line Between Vessel and CC.	NO?	YES?	***Yes because of the long lines and problems they have had.**	
Instrument Piping In Drywell	1" approx. 80'-100'	1" approx. 20'-40'	1" approx. 20'-30'	
Excess Flow Check Valves	1" Dragon Auto Bypass	1" Morata Manual Bypass	1" Dragon Auto Bypass	
Instrument Tubings Outside of Drywell	3/8" From EFCV to Instr. Rack	1/2" from EFCV to Instr Rack	3/8" from EFCV to Instr. Rack	
Approx. Length to Instr. Line	175'-250'	150'-175'	150'-175'	

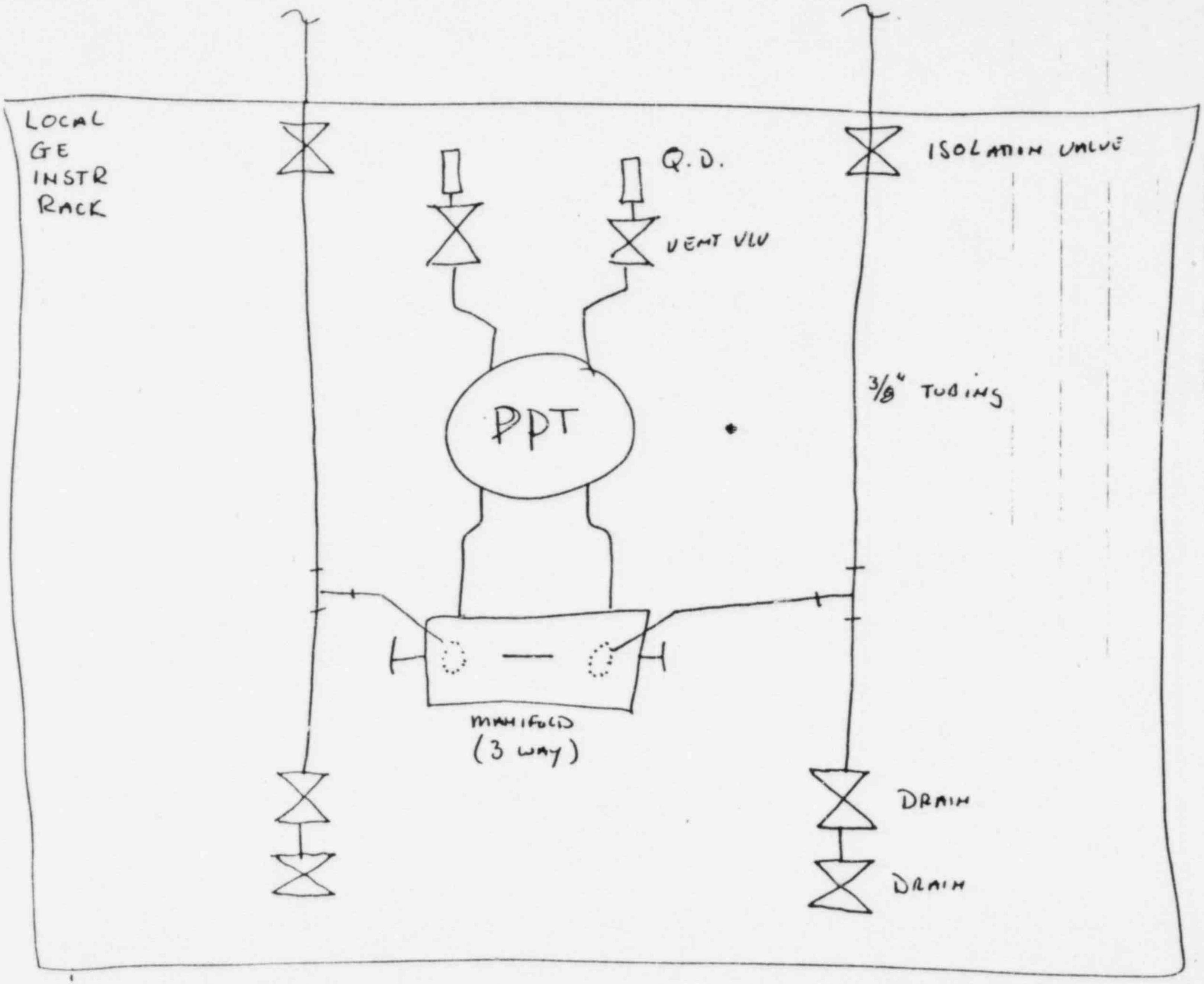
COMPARISONS WITH OTHER BWR PLANTS (CONT.)

	HOPE CREEK	LIMERICK	SHOREHAM	COMMENTS
Type of Instr.	Rosemount 1153B	Rosemount 1151	Rosemount 1151/1152	
Time Constant	Fix 20 MSec. Narrow 50 MSec. Wide Range	Adjustable Set at 50 MSec.	Adjustable Set at 50 MSec.	
Flex Hose	YES	Yes, But not (Typical) used	Yes, had problems replaced two	
Barton Instr. In Line with RPS Instruments	Yes, valved out	Yes, valved out	Yes, replaced with Rosemount Instr.	
Training of Techs.	YES	*** Yes. Required to take 4 Hrs. of Vlv. Training**	YES	
Rack Design	GE, protection around racks	GE, No protection	GE, No protection	
Problems with Bumping Racks	None Identified	None Identified	None Identified	
Labeling at Local Rack	Standard Instr. Indentification	*** Excellant. Instrument Ident. Red Warning Sign I&C only, valve position, T.S. Instr. - Indentified EQ Instr. - Indentified**	Standard Instr. I.D.	

COMPARISONS WITH OTHER BWR PLANTS (CONT.)

	HOPE CREEK	LIMERICK	SHOREHAM	COMMENTS
Manifold Valves	Hoke needle	Dragon tight needle	Dragon Floating Needle, being replaced with metering valves	
Probems with Valving In/Out Instruments	YES	*** Yes. Training Helped.**	YES	
Working on Instr. At Power	YES	*** No. Work on Problems only when down**	No. Work on problems only when down	
Pressurize Insturment before returning to service	NO	*** Yes (Helped)**	*** Yes (Helped)**	
Design changes made to prevent air problems	Added Quick Disconnect Fittings at Vent Valves	Add head tanks to vent valves	NONE	
Troubleshooting:				
Walked all instrument lines:	Yes (N5 program)	YES	YES	
Take Temperature Readings of the Instrument Line Inside Drywell	Ongoing	?	YES	


DRYWELL
RPV
CC
CC
~2'-3'
ROOT VALVE (TYP)
EFCV (TYP)
1" PIPE (TYP)
1/2" SLOPE (TYP)
3/8" TUBE (TYP)
LOCAL RACK
LOCAL RACK
EL 77
EL 77


LOCAL
GE
INSTR
RACK
Q.D.
VENT VLV
ISOLATION VALVE
3/8" TUBING
PPT
MANIFOLD
(3 WAY)
DRAIN
DRAIN

TASK SCHEDULE

ACTION ITEMS	PRE OUTAGE	DURING OUTAGE	POST OUTAGE
1	Revise backfill procedure	Backfill all lines	
2	Upgraded training techniques	Upgraded training techniques	
3	Stop work on Non-Tech Spec instruments		Expand scope of review 9/30
	Issue unique procedures	Work unique procedures by trained technicians	
4	Add temporary labeling to critical instruments	Add warning labels to instrument lines	Add permanent labeling to all critical instruments 9/1
5			Test rack for instrument valves 10/30.
			Modify existing manifold valves if required.
6	Design insulation	Install insulation	
7	Walk down instrument lines	Walk down instrument lines	Prepare design changes, if required.
*	Develop test program	Install test equipment less GETARS	Install GETARS 9/1 Monitor System with test program.

HCGS CRITICAL PATH TESTING/OUTAGE SCHEDULE