U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 84-49 / 84-12

Docket No. 50-352 / 50-353

License No. CPPR-106 / CPPR-107   Priority -   Category B / A

Licensee: Philadelphia Electric Company

2301 Market Street

Philadelphia, Pennsylvania 19101

Facility Name: Limerick Generating Station, Unit 1

Inspection at: Limerick, Pa.

Inspection Conducted: September 1 - 30- 1984

Inspectors: J T Wiggins for   10/3/84
S. K. Chaudhary, Senior Resident Inspector   Date

J T Wiggins   10/3/84
J. T. Wiggins, Senior Resident Inspector   Date

R. W. Borchardt   10/3/84
R. W. Borchardt, Reactor Engineer   Date

Robert M Gallo for   10/16/84
A. R. Blough, Senior Resident Inspector PBAPS   Date

J E Beall   10/5/84
J. E. Beall, Project Engineer   Date

Approved by: Robert M Gallo   10/16/84
R. M. Gallo, Chief, Reactor Projects Section 2A   Date

Inspection Summary: Combined Inspection Report for Inspection Conducted September 1 - 30, 1984 (Report Nos. 50-352/84-49, 50-353/84-12

Areas Inspected: Routine inspections by the resident inspectors, the senior resident inspector at another site, and a region based reactor engineer of: followup on outstanding inspection items; followup on IE bulletins and circulars; followup on construction deficiency and 10 CFR 21 reports; witnessing of new fuel inspection activities on the refueling floor; general walkthrough inspections; witnessing of portion of work under startup work orders; preoperational test witnessing and

results evaluation; design change control; diesel generator testing observations; inadvertent fire protection system actuation; review of HVAC technical tests; operating shift readiness; Shift Advisor training; steam leak detection design; and meetings onsite on 9/19/84 and on 9/24/84 between NRC management and senior licensee management to discuss the status of completion of Limerick Unit 1 and the licensee's readiness for low power licensing. This inspection involved 153 hours for Unit 1, 5 hours for Unit 2 by resident inspectors, and 179 hours for Unit 1 by region-based inspectors and a visiting senior resident inspector.

Results: Two violations were identified (paragraphs 2, 5, and 6).

DETAILS

1. Persons Contacted

Philadelphia Electric Company (PECo)

J. Clarey, Project Construction Manager
J. M. Corcoran, Field QA Branch Head
J. Doering, Operations Engineer
P. Duca, Technical Engineer
G. Leitch, Station Superintendent
J. Milito, Field Engineer
J. Spencer, Director, Start-up

Bechtel Construction Incorporated

R. Bulchis, Project Engineer
W. McCullough, Project Start-up Engineer
G. Memula, Resident Project Engineer

General Electric Company (GE)

R. Ballou, Start-up Operations
A. Jenkins, Operations Manager
P. Pagano, Start-up Operations

Also, during this inspection period, the inspectors discussed plant status and operational readiness with other supervisors and engineers in the PECo, Bechtel and GE organizations.

2. Followup on Outstanding Inspection Items

1) Bulletins

a) (Closed) IEB 80-12: Decay Heat Removal System Operability

This IEB described an event at Davis-Besse, Unit 1, in which all decay heat removal capability was lost while the plant was in a refueling mode. Licensees were requested to review their procedures and systems to prevent occurrence of similar events.

The Limerick licensee reviewed the hardware associated with decay heat removal: principally the RHR and RHR Service Water (RHRSW) Systems. Redundant and diverse flow paths for decay heat removal were identified. These included shutdown cooling from RHR loops A or B and a feed and bleed path from the suppression pool, through a low pressure ECCS system to the pressure vessel, then back to the suppression pool via the main steam safety-relief valves. Additionally, RHR intertie lines were added so that pumps C or D could be used in place of pumps A or B respectively, for shutdown cooling service. Further, a manual override feature was added to the automatic radiation isolation on the RHR heat exchange service water inlet and outlet valves.

The licensee also included a stipulation against a degradation in decay heat removal equipment in procedure A-41 which requires the shift supervisor or shift superintendent to consider the adequacy of safeguarding against a loss of redundancy and diversity of decay heat removal capability prior to releasing equipment for maintenance.

The inspector noted that the Bases for Technical Specification (TS) 3/4.9.11 implies considerations for maintaining adequate decay heat removal capability have been included in this TS. The licensee further committed to provide a Special Event procedure to cover loss of shutdown cooling to address the following alternate cooling sources: fuel pool cooling, reactor water cleanup and control rod drive hydraulic systems.

b) (Closed) IEB 80-15: Possible Loss of Emergency Notification (ENS) with Loss of Offsite Power

This IEB described the loss of the ENS as a result of loss of offsite power events. It requested operating licensees to review the power supply to their ENS, to modify the power supply if it was not uninterruptible or powered from an otherwise reliable source, to test the system and to implement a procedural requirement to notify the NRC Operations Center via commercial line within 1 hour of a loss of the ENS.

PECo was not required to respond to the NRC in writing regarding the ENS for Limerick. However, the inspectors reviewed the power supply to the ENS and reviewed site administrative procedures. During this review, the inspectors examined Drawings E-580 Sheet 4 of 4, E-39 and E-159 Sheet 2 of 3, Administrative Procedure A-31 regarding event reporting and 10 CFR 50.72.

According to E-39 and E-159, the ENS receives power from 480 VAC Motor Control Center (MCC) D114-G-D. This MCC is powered from the D11 4160 V Safeguard Bus through Load Center B201 and breaker 52-20124. On loss of offsite power, 52-20124 trips open. The breaker automatically recloses about three seconds after the D11 bus is reenergized by the D11 diesel. However, if a loss of coolant accident (LOCA) occurs coincident with the loss of offsite power (LOOP), D114-G-D will not automatically reenergize.

The inspector determined that, for LOCA-LOOP conditions, operators are directed to reclose 52-20124 by Special Event procedure SE-10. Further, procedure A-31 lists loss of the ENS as a 1 hour reporting criterion.

The inspector had no further questions.

c) (Closed) IEB 80-25: Operating Problems with Target Rock Safety-Relief Valves at BWRs

This bulletin described five events that occurred over a three month period involving two types of malfunctions of Target Rock (TR) safety-relief valves (SRV). Three of the events involved failures of the SRV and the remaining two resulted from failures of the nitrogen supply system pressure regulation. The bulletin required the licensee to: 1) initiate quality control procedures to assure inspection of the solenoid actuators, 2) revise operating procedures to include specific overhaul requirements, and 3) review SRV pneumatic supply systems making modifications as required. The solenoid actuators were inspected by Target Rock Corp. in a program accepted by General Electric Company. General Plant Procedure, GP-2 "Normal Plant Startup" includes steps which reference IEB 80-25 and requires that a failed valve be removed and replaced with a new or reconditioned valve, or that the failed valve be removed from service, disassembled, inspected, adjusted and pressure set point tested with steam. The licensee is installing relief valves in the pneumatic supply system to prevent overpressurization of the existing solenoid valves. Installation of relief valves is documented in Design Change Package 0275 and is scheduled for completion prior to initial criticality.

2) Circulars

a) (Closed) IEC 79-18: Proper Installation of Target Rock Safety-Relief Valves

This circular provided information on two potential problems associated with Target Rock safety-relief valves (SRV). One potential problem concerned the use of excessive or insufficient insulation around the valve body and the second concerned valve modifications. The licensee has evaluated the information provided and taken the recommended actions. The inspector verified through direct observation that the valves have been insulated in accordance with the vendor's technical manual. M-041-006 (Maintenance Procedure for the Main Steam Relief Valve Solenoid Valve and Air Operator Assemblies) was reviewed to verify adequacy. The inspector also reviewed a letter from the Target Rock Corporation which documents that the correct type of air operator diaphragms are installed in the licensee's SRVs.

3) Information Notices

a) (Closed) I.E. Information Notice No. 84-64: BWR High Pressure Coolant Injection (HPCI) Initiation Seal-In and Indication

This information notice advised recipients of a potential problem in the initiation logic (both automatic and manual) that might prevent the HPCI initiation from going to completion. The problem is compounded by erroneous system status indication that could be confusing to the operator. The Reactor Core Isolation Cooling (RCIC) system was also found to have a similar problem. On automatic actuation, the HPCI pump discharge would not start to open until the steam inlet valve and the turbine stop valve were no longer fully closed and the initiation signal was still present. For manual actuation, the operator must hold the manual pushbutton for 12 seconds (long enough for the steam valves to leave their fully closed position) in order for the pump discharge valve to open.

The licensee evaluated this information notice and determined that operator precautions were appropriate to assure proper verification of the HPCI and RCIC systems. Permanent labels have been placed by the manual pushbuttons that instruct the operator to hold the HPCI button for 13 seconds and the RCIC button for 2 seconds. The licensee also determined that no long term permanent logic modifications would be required or desired since, if the initiation signal were to clear before system initiation was completed, 1) HPCI/RCIC injection would no longer be necessary and 2) the HPCI system would be operating in the minimum flow mode eliminating the need to restart the entire system should a later injection be required. The inspector has no further questions at this time.

4) Violations

a) (Closed) Violation 84-26-02: Failure to control testing of the Control Room Isolation System

The licensee revised preoperational procedure 1P32.2 dealing with the Control Room Isolation and Purge system and reperformed the entire test. The revised procedure correctly tested valve HV-78-020A which was the inspector's initial concern. The licensee's response to this violation, dated September 6, 1984 was reviewed and found to be acceptable. In addition to reperforming 1P32.2, the licensee has taken the following actions to prevent recurrence of this and similar items:

- o The startup Administrative Procedures have been revised to reduce the numbers of TCNs.
- o A test summary of the results of preoperational testing, detailing TCNs, will be provided to the test review board and NRC to aid in review.
- o Permanent plant personnel will participate in each preoperational test to review all TCNs.

b) (Closed) Violation 84-26-03: Failure to Control Test Program for Containment Isolation System

The preoperational test program had not included all testing necessary to demonstrate the suitability of the containment isolation and nuclear steam supply shutoff (NSSS) system in that certain containment valves identified in FSAR Table 6.2-17 were not tested as part of the preoperational test program. To correct this situation, the licensee added a Test Change Notice to procedure 1P73.1 (Containment Atmosphere Control System) that tested the previously untested valves. The inspector reviewed the licensee's response to this violation dated September 6, 1984 and found that it adequately addressed the inspector's concerns. The inspector has no further questions at this time.

5) Unresolved Items and Follow Items

a) (Closed) Unresolved Item 83-23-03: Closeout comments on Public Address (PA)/Evac Alarm (EA) Response Characteristics in High Noise Areas

The inspector was concerned with the licensee's plans to assure adequate auditory response characteristics of the PA, EA and other in-plant communication systems in high noise areas. The licensee has drafted a routine test procedure RT-1-111-641-0 titled Internal Plant Noise Level Monitoring which is to be performed quarterly and after installation of new equipment with significant noise impact. RT-1-111-641-0 provides specific direction for conducting local sound level measurements throughout the plant with specific measurement locations identified to ensure adequate plant coverage. The licensee's current Startup Test Program schedule shows that this test is to be run during test condition six. The inspector has no further questions at this time.

b) (Closed) Unresolved Item 50-352/83-23-05: Drain Lines Violating Secondary Containment Integrity

The inspector reviewed DCP 0369 which provided the following corrective actions to seal various drain line connections between the refueling floor and the Unit 1 reactor enclosure:

- installation of plugs in all floor drains
- installation of plugs in each service box drain
- sealing of the service box covers
- installation of check valves in the overflow line for the reactor enclosure cooling water (RECW) heat tank and in the drain line from the refueling floor emergency shower.

Full implementation of this DCP would solve the secondary containment violation concern for initial Unit 1 operations. This is because the DCP completes the isolation of the refueling floor from the Unit 1 reactor enclosure. Currently, the integrity of the refueling floor is not an issue because the licensee has justified to NRR its case for deferring connection of the Standby Gas Treatment System to the refueling floor. Also drains from the refueling floor to the Unit 2 reactor enclosure are not yet of concern because Unit 2 is still in construction.

The inspector examined completed work and work in progress to implement the DCP. He noted that: temporary floor drain plugs were being replaced with permanent ones; plugs were installed in the service boxes and sealing material was provided; and the check valves were installed in the correct orientation. The inspector also reviewed FMR 106748 which was used to order the check valves and verified it contained instructions to load them to hold 8 inches of water; and reviewed the part of the results package for the Standby Gas Treatment System preoperational test (P70.1) that demonstrated the system's ability to maintain the required 0.25 inch wg vacuum in the reactor enclosure.

During the course of his review, the inspector determined that neither DCP 0369 nor any other document provided a revision to P and ID M13 to reflect the current as-built condition of the RECW head tank overflow line.

The inspector informed the licensee that, because all applicable controlled drawings were not revised as a result of implementation of a design change, the licensee had violated the requirements of 10 CFR 50, Appendix B, Criterion III. (50-352/84-49-01) After the inspector's discussions, the licensee issued Field Change Request D389F to appropriately revise M-13. See paragraph 16 of this report for corrective actions taken as a result of this inspection.

c) (Closed) Follow Item 50-352/84-01-01: Licensee to revise the Nuclear Review Board (NRB) Charter to make it agree with the FSAR

The inspector reviewed draft Revision 8 to the NRB Charter which incorporated the requirement for NRB to review the semi-annual audit program and schedule for Limerick and Peach Bottom. In addition, the inspector reviewed a 9/7/84 letter from PECo to NRR which forwarded Licensing Document Change Notice (LDCN) FS-662. This LDCN revised the FSAR statements regarding the participation of alternate NRB members such that the prohibition against having more than two alternate members voting at any NRB meeting was removed.

d) (Closed) Follow Item 50-352/84-10-05: Continued use of MOVATS to set Limitorque valve operators

The inspector reviewed PMQ-500-032 and PMQ-500-087 which documented and implemented the licensee's plans to continue the use of the MOVATS test equipment during the maintenance of Limitorque operators.

e) (Closed) Licensee Identified Item 50-352/84-14-01: Inspection discrepancies on GE and Bechtel-designed hangers

As stated in NRC Inspection Report 84-14, a number of nonconforming conditions were identified by Bechtel QC as a result of reinspections of GE-designed hangers. As a result, a sample of Bechtel-designed hangers previously inspected by the two Quality Control Engineers (QCE) involved were reinspected. In the case of one of the QCEs, 1 minor condition was identified; for the other QCE, 16 of 25 hangers reinspected had various nonconforming conditions. The nonconforming conditions were identified on NCR 9722.

The inspector noted an internal memorandum dated 4/28/84 from Bechtel QA to Bechtel QC requesting a reinspection of 55 additional hangers inspected previously by the QCE whose work was suspect. In response, QC performed the reinspections and documented the nonconformances noted on NCR 10173 and 10174. The three NCRs (9722, 10173 and 10174) were forwarded to Resident Engineering for disposition. These conditions included:

Description	No. of Occurrences Found
Hanger Location Deviation	8
Weld Size/Length and Condition Problems	21
Clamp/Strut Installation Problems	4
Snubber Swing Angle Problems	5
Drawing/Dimensional and Other Problems	20
Total	58

Each nonconforming condition was analyzed by Resident Engineering and found suitable as is. Based on these dispositions and on the knowledge of Bechtel standard hanger design and weld design practices, no further reinspections were performed.

The inspector had no further questions about this item.

f) (Closed) Unresolved Item 50-352/84-26-01: Licensee to Reevaluate SDR-136 for reportability

The inspector reviewed the reportability evaluation for SDR 136, which dealt with crushed ball floats in the scram discharge volume (SDV), dated 8/29/84. The evaluation determined that this condition was not reportable per 10 CFR 50.55e.

The bases relied upon by the licensee in completing the evaluation were reviewed by the inspector. As stated in the evaluation, the level switches had been supplied by GE with a specified hydrostatic pressure of 1500 psig. Following communications between the switch manufacturer, Magnetrol, and Bechtel, a hydrostatic test pressure of 1920 psig was identified for site construction testing of the SDV. Following tests at 1920 psig, 2 switches failed due to crushed floats. Subsequent discussions with Magnetrol indicated the maximum test pressure for the 2 failed switches was 1800 psig. The potential impact of the failures of the SDV switches was determined to be the loss of redundancy in the high SDV water level reactor trip.

The two failed switches were replaced. The remaining switches were verified functional during preoperational testing.

The inspector concluded that this SDR could be considered not reportable. The potential impact of the failure of the float level switches would have been the loss of diversity, not redundancy, in SDV level detection; the d/p type level switches would have remained operable. Further, the failure of these floats experienced at Limerick did not meet the requirements for significance per 10 CFR 50.55e in that the failures did not require extensive evaluation, redesign or repair to correct the failures. Therefore, the inspector had no further questions regarding SDR-136.

g) (Closed) Unresolved Item 84-38-02: Entrance and Exit Lanes in the TSC are Inadequately Separated

The inspector verified that the licensee has adequately separated the entrance and exit lanes in the Technical Support Center.

h) (Closed) Follow Item 84-42-01: Licensee to verify the crack mapping area during the Structural Integrity Test (SIT) to have been at least 40 ft^2.

The inspector noted that the licensee had determined, by measurement, that the crack mapping area used during the SIT was 44 ft^2.

i) (Closed) Follow Item 84-42-02: Licensee to perform Local Leak Rate Tests on penetrations remaining in LLRT program and to establish and implement a disposition relative to four containment purge and vent valves

The inspector reviewed SWO 34A-61, 34A-62, 70A-36 and 70A-37 which were written to modify the four containment purge and vent valves involved. As a result of Field Change Request P 1308F, valve HV-57-103 had its motor operator removed, its stem packing box modified to provide LLRT connections and had its stem seal welded to prevent leakage. The valve designation was changed to M57-1125. Similarly, HV-57-113, HV-57-122 and HV-57-125 were modified and their designations changed to M57-1123, M57-1124 and M57-1126 respectively.

The inspector also reviewed SWA 34A-33 and 70A-78 which documented acceptable LLRT results for the modified valves. Further, the inspector noted that FDCN 40 updated the applicable P & ID.

The completion of the LLRT program will be reviewed at a later date.

6) Construction Deficiency Reports and Part 21 Reports

a) (Open) CDR 84-00-10: Diesel Oil Storage Tank Water Intrusion

The licensee reported, by phone on 8/9/84 and by letter on 9/5/84, an event involving an inadvertent intrusion of water into all 8 diesel fuel oil storage tanks. The water entered the tanks via a common drainage system and each tank's vacuum relief valve. The licensee's investigation revealed that plant construction workers had routed the discharge hoses of temporary dewatering pumps from various sources into a manhole which was mistaken for a nearby storm drain. The resulting volumetric flow rate of water exceeded the capacity of the manhole drainage line, so that the water in the manhole rose and began to backflow into the common discharge header As the water filled the manhole, the level rose to a point where it exceeded the elevation of the diesel fuel oil tank valve pit drainage ports, and water began to backflow into the valve pits. Water flowed into the vacuum relief inlet of the combination tank vacuum/pressure relief valves which are located approximately 15" above the floors of the valve pits. When the water level rose above these valves, the vacuum relief discs unseated (set to relieve at 0.5 oz differential force) and water flowed into each of the tanks.

The licensee implemented short term corrective actions including: (1) dewatering the 8 tanks; (2) installing permanent manhole covers to avoid future error; (3) cleaning of the valve pits; and (4) developing a weekly procedure for checking the pits free of water.

The inspector reviewed SWA 23B-16, SWO 20C-12, SFR 20C-10 and accompanying QC records which documented completion of actions (1) to (3). Further, the inspector noted that procedure RT-6-092-900-1 implemented the weekly inspections described in (4) above.

The licensee also identified long term corrective actions, including hardware modifications, which will be completed prior to the end of the first refueling outage.

The inspector had no further questions on the licensee's short term actions. The long term actions will be reviewed in a subsequent inspection.

b) (Closed) CDR 84-00-14 and Part 21 84-88-01: Design of missile shield doors by W.J. Wooley Company

In a letter dated 7/5/84, the Vice President of the W.J. Wooley Company informed NRC of apparent defects in the design of missile-resistant doors which resulted from errors in the design calculations for these doors. The errors identified had the potential to result in the thickness of the doors being less than required to resist tornado-generated missiles. As indicated in the 7/5/84 letter, 7 doors at Limerick were affected; 5 for Unit 1 and 2 for Unit 2. The licensee filed a CDR regarding this problem on 8/23/84.

The inspector reviewed Bechtel NCR 10198, written to track the corrective actions taken in regard to the problems identified by Wooley. The NCR described the function and location of each of the doors as follows:

Door	Location
1. Personnel Airlock Door 193	Reactor Encl., Area 17, Elev. 217'
2. Equipment Airlock Door 195	Reactor Encl., Area 16, Elev. 217'
3. Missile Door 196	Reactor Encl., Area 15, Elev. 217'
4. Missile Door 205	Control Encl., Area 8, Elev. 217'
5. Personnel Airlock Door 289	Reactor Encl., Area 16, Elev. 217'
6. Equipment Airlock Door 293	Storage for Unit 2
7. Missile Door 294	Storage for Unit 2

Through discussions with the licensee, the inspector learned that representatives of Bechtel Project Engineering and Wooley met in San Francisco to determine appropriate corrective actions. Based on a reanalysis by Bechtel and advice from Wooley, 6 of the 7 doors were found suitable in the as-is condition. The remaining door, item 4 above, was found to be adequately sized, but it required added reinforcement to its door jam. This door is a double door between the condensate pump area and the 13.2 kv switchgear area. Accordingly, the NCR indicated the need for the addition of a 1.5" x 6" x 38" backing plate to the south side of the two lower halves of the jam. This addition to the jam was found to be completed by 9/30/84. Installation of the backing plates does not require any disassembly of the existing door arrangement.

c) (Closed) CDR 84-00-16: Improperly Sized Connecting Plugs in General Electric Protective Relays

In a letter dated 8/30/84, the licensee reported the corrective actions taken to address a problem identified with some connecting plugs in protective trip relays. These relays exist in the 13.2 kv, 4 kv and 2.3 kv switchgear breakers onsite. As described in the letter and in Startup NCRs S-597-E and S-1077-E, the problem involved snug-fitting plugs which may prevent the successful operation of the protective relays in the breaker tripping mechanisms. A 6/25/84 GE internal memorandum identified the cause to be the use of an improper mold in the manufacturing of the plugs in 1977.

The inspector reviewed SNCR S-597-E and S-1077-E, reviewed Startup Work Authorization 4A-68 and observed the corrective action implementation on selected breakers. These documents indicated that the relay plugs in all Unit 1 4 kv switchgear and in that part of Unit 2's 4 kv switchgear needed to support Unit 1 operation were tested for tightness. Those that were found to be excessively tight were replaced with plugs provided by GE. Further, Bechtel NCR 10357 was written to track the corrective actions for other Unit 2 breakers.

d) (Closed) CDR 84-00-18: Bettis HVAC Actuators with Swollen Seals

In a letter dated 8/30/84, the licensee informed NRC of a potential problem regarding actuators for HVAC dampers manufactured by the G.H. Bettis Co. Ethylene Propylene seals in the actuators could absorb the Mobil 28 grease used in the actuator manufacture, causing a swelling of the seals. The result could be a slower-than-desired response time for the affected actuators.

The inspector reviewed the list of potentially affected actuators and found that they included isolation dampers in the containment purge lines, the reactor enclosure and refueling floor HVAC systems, in the reactor enclosure recirculation system, the standby gas treatment system and the control structure HVAC system. These valves receive automatic actuation signals (either to open or close) during containment, reactor, refueling or control room isolation events.

The inspector also reviewed the licensee's evaluation for this problem. He noted that the evaluation indicated that seal degradation would occur over a short period of time, after which no further swelling would occur. Therefore, if the actuators satisfactorily passed preoperational testing, no further immediate actions were warranted.

The inspector noted that no stroke time degradation had been identified during testing. However, the licensee committed to replace the seals and the grease during the first scheduled maintenance outage.

e) (Closed) Part 21 Item 84-88-05: Paul-Munroe Actuators

In a 8/30/84 letter to NRC Region I, Paul-Munroe Hydraulics Inc. informed NRC of problems in HVAC damper operators at Limerick Generating Station. Similarly designed valves also have been installed at Byron, Braidwood and WNP 1 and 4. In a 9/13/84 letter, PECo informed Region I of its corrective actions.

The defective conditions include loss of hydraulic accumulator pressure due to leakage from solenoid-operated directional control valves, leakage from the piston seals in the actuators or loss of the accumulator gas precharge. The effect of the defects is the frequent cycling of the actuator's onboard hydraulic system in order to maintain pressure in the accumulator. This frequent cycling could cause the operator internal temperatures to exceed normal values and reduce the service life of the component.

PECo informed NRC Region I of the Part 21 and corrective actions taken in a letter dated 9/13/84. The letter indicated 18 operators from Unit 1 and common were potentially defective in the reactor enclosure and control enclosure HVAC systems.

The inspector reviewed documentation provided by the licensee and determined each of the 18 valves had been repaired.

3. Plant Tour

Periodically during the inspection period, the inspectors toured the Unit 1 containment, the reactor enclosure, the control enclosure, the diesel generator enclosures, the radwaste enclosure, the offgas enclosure, the and Unit 2 reactor enclosure. The inspectors examined completed work, and work in progress for: indications of defective material and/or workmanship, equipment protection, nonconformances to technical requirements, housekeeping, and general adherence to project procedures. The inspectors also reviewed drawings, specifications, procedures, and reports to evaluate their adequacy, and to assess the state of completion of the facility. Special emphasis was placed on examination of systems for as-installed condition, repair/modification work under the startup work orders (SWOs) and tagging of equipment.

No violations were identified.

4. Preoperational Test Witnessing and Test Evaluation

1) The inspector witnessed the performance of portions of the preoperational test listed below to verify that the Test Director was knowledgeable of the methods and purposes of the test and of the administrative requirements associated with preoperational testing (e.g., Test Exception control and Test Change control). The conduct of the following test was also observed to verify compliance with the applicable test procedure:

P 83.2A ADS (NSSS) Test of High Drywell Pressure Permissive Bypass Feature

2) The inspector reviewed the following preoperational test reports to evaluate test result acceptability. Further, he verified the adequacy of the licensee's evaluation of test results, the adequacy of test exception and test change notice resolution and the licensee's compliance with established review and evaluation procedures. The inspector also performed selected independent calculations to assure acceptance criteria were met.

Except as discussed later in this section, the inspector had no resulting comments or concerns about the following preoperational test reports:

1P 3.1 (A through H) 13.2 kv Unit Auxiliary Power System
1P 7.1 Standby DC Lighting
1P 13.2 Fire Protection CO_2 System
1P 13.3 Fire Protection Air Foam System
1P 13.4 Smoke Detection System
1P 16.1 Residual Heat Removal Service Water (RHRSW) System
1P 25.1 Primary Containment Instrument Gas

1P 28.2 Spray Pond Pump Structure HVAC System
1P 33.1 Turbine Enclosure HVAC System
1P 44.1 Condensate System
1P 50.1 Reactor Core Isolation Cooling System
1P 52.1 High Pressure Coolant Injection System
1P 55.1 Control Rod Drive Hydraulic System
1P 56.1 B Rod Worth Minimizer
1P 56.1B1 Rod Worth Minimizer Back-up Computer
1P 57.1B Uninterruptible AC Power System
1P 58.1 Reactor Protection System
1P 60.1 Drywell HVAC System
1P 64.1 Reactor Recirculation System
1P 65.1 Radwaste Enclosure HVAC
1P 66.1 Reactor Enclosure Unit Coolers
1P 69.3B Reactor Coolant Boundary Leak Detection System
1P 83.2A Auto Depressurization System
1P 85.1 Cathodic Protection System
1P 91.1 Plant Annunciator System
1P 91.1A Plant Annunciator System
1P 91.1B Radwaste Control Room Annunciator System
1P 93.3 Main Turbine Supervisory System
1P 99.1 Reactor Enclosure Cranes
1P 99.3 Public Address and Evacuation System

a) 1P 50.1 Reactor Core Isolation Cooling (RCIC) System

The inspector reviewed the test results for the RCIC system and had two questions regarding the net positive suction head (NPSH) calculations performed in step 7.4.4.1. The inspector independently calculated the NPSH available to the RCIC pump when it was taking suction from the condensate storage tank (CST), using the temperature and pressure data in the test and data from the ASME Steam Tables, Fourth Edition. The NPSH value obtained by the inspector was 97.07 feet. However, the test procedure results indicated 90.57 feet. Upon questioning of the responsible Startup Engineer, the inspector determined that the Startup Engineer had used a less accurate set of steam tables to calculate NPSH. Further, the inspector learned that the Test Review Board had also identified the discrepancy, but because the NPSH value in the procedure greatly exceeded the 20 feet required, a decision not to change the test procedure results was made.

The inspector also noted that in step 7.4.4.1, the NPSH available was to be corrected to show that which would have been available if the CST had been at its lowest usable level (i.e., 3 ft. 10 in.). However, the actual CST level at the time of the test was not recorded in the procedure. The inspector was informed by the Startup Engineer that the CST level was 35 ft. Using this number, the corrected NPSH result was acceptably verified.

b) <u>1P 60.1 Drywell HVAC System</u>

The inspector reviewed the results of 1P60.1 and questioned two aspects of the test. For each drywell unit cooler, there are two fans. These fans have a feature whereby the standby fan starts if the running fan stops. Upon discussions with the responsible Startup Group Supervisor, the inspector learned that the automatic transfer results from the detection of a low flow condition in the HVAC ducting.

In Startup Field Report (SFR) 60A-11, Bechtel provided the acceptance criterion for the automatic fan transfer to be 60 seconds maximum 45 seconds minimum. The inspector noted that all 8 fan combinations failed this criterion. Five sets transferred in 30 seconds; the remaining three exceeded the maximum time by up to 3 minutes. Test Exception (TE) 32 documented the above problems.

The inspector noted that Startup had closed TE 32 based on a "use as is" disposition of SFR 60A-14 provided by Bechtel. This disposition implied that the delays were caused by slow response of the associated flow switches. However, the inspector questioned the adequacy of the basis for this disposition. The inspector discussed this problem with the Startup Director who agreed to reexamine the resolution of TE 32.

The inspector also noted that the drywell cooler condensate weir flow detection system was not tested in 1P 60.1. Based on discussions with the Startup Director, the inspector determined that this system was a late facility modification which had not been scoped into any other preoperational test. The inspector stated that testing of this system should be addressed by the licensee because the system is one of the methods discussed in Technical Specifications for reactor coolant pressure boundary leakage detection.

In consideration of the above two problems, the inspector considers the acceptability of P 60.1 to be unresolved. (50-352/84-49-02)

c) <u>1P 83.2A Automatic Depressurization System (ADS)</u>

This procedure covered testing of the revised actuation logic for the ADS system. In response to TMI Item II.K.3.18, the licensee changed the logic to provide a bypass of the high drywell pressure requirement for ADS initiation if the low reactor vessel water level exists for 6.5 to 7.5 minutes. The inspector had no questions regarding the results of this test. However, he determined that an FSAR change was necessary to show the current ADS logic as-built conditions. The inspector was informed by a Startup representative that licensing document change notice 696 was being prepared to cause this change.

5. New Fuel Inspection and Storage

The inspector periodically observed the licensee's activities associated with new fuel movement, inspection, channeling, and placement into the spent fuel pool. These activities were inspected for compliance with: LGS administrative and fuel handling procedures, radiological control practices, NRC regulations and license conditions.

During this inspection period, the licensee completed fuel inspection activities with the placement of all 764 channelled bundles into the spent fuel pool (SFP). With the exception of the items discussed below, the inspector found the licensee's activities to be in compliance with applicable requirements.

During a review of the fuel handling (FH) procedures being used on the refueling floor, the inspector questioned the status of a number of temporary changes which had been made to the FH procedures. FH procedure 201, step 9.1.7, had a temporary change dated August 3, 1984 and FH-210, step 3.1.1, had a temporary change dated August 2, 1984.

LGS Administrative Procedure A-3 titled "Procedure for Temporary Changes to Approved Procedures" states that the Plant Operating Review Committee (PORC) shall review temporary changes to procedures within fourteen days of implementation and the Station Superintendent shall approve temporary changes within the same fourteen days. The inspector determined that as of September 11, 1984, neither of these temporary changes had been reviewed by the PORC or approved by the Station Superintendent.

The inspector informed the Station Superintendent that because the Administrative Procedures contorlling the issuance, review, and approval of temporary changes were not followed, a violation of 10 CFR 50 Appendix B Criterion V resulted. (50-352/84-49-03) See paragraph 16 of this report for corrective actions taken as a result of this inspection.

6. Design Change Control

During a recent NRC Region I audit of Technical Specifications, the inspector identified inconsistencies among the design documents describing the Reactor Water Cleanup System (RWCU) isolation signals. The working copy of the Technical Specifications and Elementary Drawings B21-1090 E 12.19 and C41-1030 F 4.2 indicated that both the RWCU inboard and outboard suction isolation valves close on Standby Liquid Control System (SLC) initiation. However, the inspector noted that Functional Control Drawing (FCD) G31-1020 F 1.10 showed that only the RWCU outboard isolation valve would close on SLC initiation. ECN-NJ36290, dated July 9, 1982 which implemented ECA-800619-2 Rev. 4, did not result in a change to the FCD when the Elementary Drawings were changed.

Inconsistencies were also identified in the FSAR concerning RWCU isolation on SLC initiation. FSAR Table 6.2-17 indicated that both the inboard and outboard isolation valves close on SLC initiation, but FSAR Section 7.7.1.8.3.2 and FSAR Figure 7.7-11 showed that only the outboard RWCU isolation valve closed.

However, the inspector verified that the applicable preoperational test, IP-53.1, demonstrated that the installed devices performed as called for in the Elementary Drawings.

The inspector informed the licensee that the failure to assure all drawings affected by a design change were appropriately revised is a violation of 10 CFR 50 Appendix B, Criterion III. (50-352/84-49-04) See paragraph 16 of this report for corrective actions taken as a result of this inspection.

7. Diesel Generator Testing Observation

On 6/20/84, while observing the LOCA-Loss of offsite power portion (LOCA-LOOP) of preoperational test P 100.4 on the D14 diesel generator, the inspector observed that all four diesel generators received a trip signal from flow switches in the fire protection system. The inspector discussed this situation with representatives of the licensee on 6/21 and again on 9/11/84.

The inspector learned that the flow switches had actuated, giving false indications of fire protection water flow to each diesel generator cell, as a result of the loss and subsequent regaining of the 10Y202 120 vac instrument panel during the LOCA-LOOP test. This panel deenergizes on a LOOP and must be manually reenergized by the operators when power is restored to the D14 safeguard bus.

The inspector, on 9/11/84, reviewed Startup Field Report (SFR) 13A-18 Design Change Package (DCP) 0474 and Startup Work Authorization (SWA) 24A-132 which identified the problem and specified and implemented the corrective actions. According to the SFR, each flow switch (3 per diesel generator) is thermally activated, using a heater to balance a bridge circuit. Upon loss of power, the heater deenergizes and causes the bridge to become unstable. Upon reenergization, the flow switch trips (indicating flow) until the heater can raise the switch temperature and stabilize the bridge.

The inspector further determined that in the event of an actual LOCA-LOOP, the diesels would not have tripped because each diesel generator's fire protection trip is automatically bypassed during a LOCA. However, during testing or during a LOOP without a LOCA, the diesel trips would have occurred.

The specified corrective action involved the replacement of a relay in the fire protection trip circuits with a time delay pick up relay set to provide a 60 second time delay in the flow switch trip function. This time delay would inhibit the diesel generator trips while the flow switch bridges stabilize.

The inspector had no further questions at this time.

8. Inadvertent Fire Protection System Actuation

At about 2:05 p.m., 9/9/84, the fire protection deluge system for the 4B autotransformer in the 500 kv switchyard inadvertently initiated, spraying down the 4B autotransformer. The 4B and 4A autotransformers are 500/220 kv units connected in parallel which supply a 220 kv feed to the 220 kv switchyard. Tertiary windings on each transformer supply 13.2 kv power to the 20 Station Auxiliary Bus which, in turn, feed the 20 Startup Bus and the 201 Safeguard Transformer. The 201 Safeguard Transformer supplies one of the two sources of offsite power to the Unit 1 4160 v Safeguard Buses.

As a result of being sprayed, the B phase potential transformer associated with the 4B unit arced-over and failed. This failure resulted in the actuation of a differential relay which caused the isolation of both the 4A and 4B units with the attendant loss of the 220 kv feed from the 500 kv yard along with the 13.2 and 4.16 kv feeds.

A security guard, apparently seeing the arc flash and hearing the 4A/4B breakers open, assumed an explosion and fire had occurred and notified operators in the main control room. The Shift Superintendent immediately dispatched operators to the yard and called the Linfield Fire Company for assistance. When the operators and fire company arrived at the 500 kv yard, located outside the protected area boundary, they found no indications of an explosion or fire, but only some indications of distress on the B phase potential transformer. The station then released the Linfield Fire Company.

At about 5:00 p.m., after isolating and blocking the 4B autotransformer deluge system and opening the 4B disconnects, the 4A unit was restored to service along with the 220 kv, 13.2 kv and 4.16 kv feeds. Because Unit 1 was receiving power from the 220 kv yard during the event, a loss of power to Unit 1 did not occur.

No violations were identified.

9. Review of HVAC Technical Tests

Technical Tests were those checks made of system components to assure their readiness for preoperational testing. Technical Tests were governed by the controls of the Startup Technical Program and the Startup Administrative Manual. Typically, for each major plant system, there were procedures for initial operations of the system prime movers (i.e., pumps, fans, motors, etc.) and for certain valves.

The inspector reviewed those aspects of the Startup Technical Program being applied to HVAC systems. This review started in May 1984. Based on discussions with Startup personnel, the inspector learned that Startup supervision had already identified some discrepancies in the HVAC Technical Test records. These discrepancies involved incomplete records or records which indicated component performance was outside the acceptance criteria boundaries. Further, the inspector learned that, as a result of these identified discrepancies, the Project Startup Engineer had directed a Group Supervisor to conduct an overall audit of HVAC test records.

The inspector reviewed the findings of this informal audit. He noted that discrepancies had been identified such as missing Startup Engineer (SE) initials in the record data blocks, and corrections made to the data without dated SE initials. Additionally, the audit identified some fan vibration, flow and motor current data which did not meet expected values and for which no engineering disposition was obtained. Each discrepancy was marked by a tab in the associated record; no total, trackable list of discrepancies was being maintained. However, the inspector did not find any record discrepancies other than those identified by the Startup audit.

In June, July and again in August, the inspector reviewed the Technical Test records to determine if the identified discrepancies had been corrected; in each instance they had not yet been fully corrected. Therefore, the inspector informed PECo management of his concern over the excessive time being taken to correct the records. As a result, PECo management directed Startup to expeditiously address the identified discrepancies and also directed Startup QC to perform surveillances on each record.

The inspector reviewed the Startup QC surveillance reports for systems 28E, 28J, 30A, 30C, 30I, 32A, 34A, 34B, 70A. The surveillances verified that the data was correctly recorded and that the data met acceptance criteria in each case. The inspector noted that some discrepancies had been identified on these surveillance reports, but that they were minor and each had subsequently been corrected.

The inspector had no further questions in this area. No violations were identified.

10. Operational Readiness of Shift Operations

During September 17 - 21, 1984 the Peach Bottom Senior Resident Inspector interviewed operators and managers, observed control room activities, and reviewed procedures and records, to assess the readiness of the shift organization for plant operation.

1) Status

Several organizational features and administrative controls that will become requirements at the time of licensing had not yet been fully implemented. This was discussed with management and a sampling of operators. Personnel interviewed were generally knowledgeable regarding the various requirements, the current status, and plans for implementation. Examples of items not yet fully implemented follow:

a) Shift staffing and organization.

Full shift staffing of currently licensed operators and senior operators was planned for September 24. STA's were to report on shift at that time.

Also, division of Control Operator (CO) and ACO responsibilities which had been effectively combined during construction and preoperational testing, was to be completed by then.

b) Independent Verification Provisions and Locked Valve Controls

Independent Verification Provisions and Locked Valve Controls had not been used due to the heavy work load of preoperational testing. These controls were planned for use prior to fuel load, starting with the safety related valve line ups for those systems required for fuel load.

c) Temporary Modification Controls

Temporary modification controls were in the process of being converted from the Startup's system to the plant staff's system.

d) Onshift Surveillances

Procedures for onshift surveillances (e.g., instrument checks) had not been issued. When questioned, the licensee indicated that these would be issued promptly to allow operators to gain familiarity.

2) Findings

Except as follows, the licensee's set of administrative controls was acceptable and appeared potentially effective for plant operation.

a) Administrative Procedure A-7

Administrative procedure A-7, shift operations, is unclear as to what portion of the control room is "at the controls" per 10 CFR 50.54(k). The procedure, as written, allows the unit reactor operator to briefly patrol back panels, out of sight of reactivity controls and reactor instrumentation, without first ensuring that another licensed operator will remain in the control room. The licensee stated that the procedure would be clarified; this item is unresolved. (352/84-49-05)

b) Administrative Procedure A-42

Administrative Procedure A-42, Temporary Circuit Alteration, provides for safety review of proposed temporary modifications. This review process begins at the STA and Shift Supervisor levels. The applicant did not appear to have measures to ensure awareness of A-42 requirements among engineers, technicians, and craftsmen who might have opportunity to make temporary system changes in the course of their jobs (e.g., troubleshooting, maintenance). When notified of the inspector's concern, the applicant took the following actions:

(1) Incorporated briefings on control of both temporary and permanent modifications into General Employee Training (GET);

(2) Issued a letter instructing appropriate supervisors to brief current employees on A-42; and

(3) Instructed appropriate supervisors to include training on A-42 in introductory LGS training courses, as an enhancement to the GET briefing.

The completion and effectiveness of the above measures will be routinely reviewed during subsequent inspections.

c) Administrative Controls

Several items were noted where improvement of an administrative control appears needed to enhance the strength or reliability of the control.

-- Locked valve controls. A method is needed to prevent the log from becoming unwieldy as the number of completed line entries becomes large. Supervisory review is less effective when a few "open" entries are distributed throughout many pages of completed entries.

-- Procedures. Availability to non-licensed operators of controlled procedures needs improvement to promote knowledge and use of procedures. Currently, non-licensed operators needing procedures must photocopy them in the control room. The licensee intends to place a copy of system operating procedures in a floor operator office area in the Turbine Building.

-- Event reporting. Administrative Procedure A-31 lacks plant-specific information on determining reportability of events, such as radioactive releases through the various monitored pathways.

-- Shift turnover. Excessive interruptions and disruptions were noted during one relief of the Shift Supervisor position. Controls are needed to provide smoother, more reliable transfer of information and responsibility.

The licensee's performance in the above areas will be reviewed in a subsequent inspection. (352/84-49-06)

d) Human Factors Comments

The inspector provided the following comments.

-- Small (3 x 5) instruction cards partially blocked the recorder charts for several meteorological parameters. These were removed during the inspection.

-- Primary containment isolation valve groupings are not visually identifiable, such as by a visual code on their control switches.

-- There is no method, such as a posted, simplified drawing, to assist operators at the control panels in following flow paths of complex systems, such as ESW.

Within the scope of this review, no violations were identified.

11. Review of the Steam Leak Detection System Design

As a result of a problem identified at Shoreham regarding the response of the steam leak detection system (SLDS) during a loss of offsite power test, the inspector reviewed the design of this system at Limerick. At Shoreham, the recovery of power to the SLDS resulted in spurious isolations of both the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems.

At Limerick, the SLDS is a GE-supplied system with the GE Master Parts List designation of B21. As described in Section 7.6 and 7.7 of the FSAR, the SLDS monitors various process parameters and executes system isolations to prevent excessive reactor coolant pressure boundary leakage. There are four safety-related applications - main steam line leak detection, reactor water cleanup (RWCU) leak detection, RCIC leak detection and HPCI leak detection - and 6 non-safety related applications including recirculation pump seal leak detection and RHR system leak detection.

The RCIC and HPCI leak detection systems monitor, among other parameters, equipment area and pipe chase area temperatures. These temperatures are detected and signals processed by Riley Model 86 modules. In response to questions raised about these modules by the inspector, onsite GE Startup Operations personnel determined that the Riley modules exhibited undesirable response to a loss of power. The modules at Limerick are wired such that upon loss of power and subsequent reenergization, the modules momentarily simulate a high temperature condition of sufficient duration to initiate HPCI/RCIC system isolations. At Limerick, power would be lost to these modules as a result of loss of power to the 4160 volt safeguard buses and 120 v instrument ac.

To correct this condition, GE has implemented FDDR HH1-4440 at Limerick to replace two relays in each of the HPCI and RCIC isolation circuits with Agastat ETR time delay relays. The time delays will be set to allow the Riley modules to stabilize at an accurate temperature indication while inhibiting HPCI/RCIC isolations. The inspector determined that implementation of the FDDR and subsequent system retesting will be completed prior to fuel load.

The inspector briefly reviewed the impact of the above SLDS problem on the other safety-related applications. Spurious isolations of the RWCU do not present a serious challenge to safety systems or to the operator's ability to control the plant. In the case of the main steam line subsystem, the temperature modules receive power from either the A or B reactor protection 120 Vac uninterruptible power supplies (ref. FSAR section 7.6.1.3), thereby minimizing the possibility of power loss to the modules.

The inspector had no further questions at the time and identified no violations.

12. Shift Advisor Duties, Responsibilities and Training

To satisfy the industry standards endorsed by the NRC regarding minimum on-shift operating experience at near-term operating facilities, the licensee determined that one of the five operating shifts required supplementing with a Shift Advisor. This Shift Advisor would be onshift whenever the reactor is not in a cold shutdown condition. To fill the Shift Advisor position, two individuals who previously possessed senior reactor operator licenses at Peach Bottom (PBAPS) were temporarily assigned to the Limerick station. The inspector reviewed the duties, responsibilities, and reporting relationships for the Shift Advisor and the training provided to each individual.

The Shift Advisor duties, responsibilities and reporting relationships were found to be defined in a memorandum from the Operations Engineer to the Station Superintendent. As shown in the memorandum, the Advisor's role is clearly advisory in nature, interfacing with the Shift Technical Advisor (STA), the Shift Supervisor and Superintendent (SST) and the Operations Engineer. The Advisor has been specifically prohibited from operating equipment or from supervising operators in the performance of licensed duties. The Shift Advisor would routinely report to the Shift Superintendent but during emergency conditions, he would report to the STA. Further, the memorandum identified the Operations Engineer as the individual who would resolve conflicts which might arise between the Shift Advisor and the shift supervision.

Regarding Shift Advisor training, the inspector noted that a curriculum had been established and training conducted for the licensee by General Physics. The curriculum involved training in Limerick systems, technical specifications and administrative, operating and emergency procedures, with special emphasis placed on the differences between PBAPS and Limerick. Also included were plant walkdowns and simulator training. This training occurred from 8/6/84 to 9/21/84. Weekly quizzes were given to evaluate trainee progress. The licensee's Nuclear Training Section administered a three-part final written examination; the Operations Engineer and Assistant Station Superintendent administered oral and simulator examinations. The inspector noted that each candidate passed the written, oral and simulator examinations, exceeding the 70%/80% criterion for the written portion.

The inspector reviewed the written examinations, the candidate's answers and the grading of the examination to independently verify their adequacy. A Region I-based Licensing Examiner witnessed the simulator examinations. Both activities were found to be acceptably performed.

However, the inspector noted that one written answer to a question on the logic for the Automatic Depressurization System did not reflect changes made by a recent plant modification. During a discussion with the Nuclear Training Section (NTS) Supervisor, the inspector found that the two Shift Advisors were not yet on distribution for procedure and design change information. The NTS Supervisor agreed to add the two individuals to the distribution list.

No violations were identified.

13. Meetings to Discuss the Status of Completion of Limerick Unit 1 and the Licensee's Readiness for Low Power Licensing

On September 19, 1984 the Director of the Office of Nuclear Reactor Regulation and members of the NRC staff met with senior licensee management to discuss the readiness of Limerick 1 for low power licensing. The meeting consisted of a plant tour and a presentation by the licensee. Attendees included the following:

PECo

L. Everett, Chairman of the Board and Chief Executive Officer
V. Boyer, Senior Vice President - Nuclear
S. Daltroff, Vice President - Electric Production
J. Kemper, Vice President - Engineering and Research
W. Ullrich, Nuclear Generation Division
G. Leitch, Station Superintendent
J. Corcoran, Field QA Branch Head

NRC

H. Denton, Director of the Office of Nuclear Reactor Regulation
T. Novak, Assistant Director of Licensing
R. Martin, Project Manager, LB-2, NRR
F. Coffman, Reliability and Risk Assessment Branch, NRR
W. Russell, Chief, Systematic Evaluation Programs Branch, NRR
S. Stern, Technical Support Branch, NRR
V. Benaroya, Chief, Chemical Engineering Branch, NRR

On September 24, 1984 the Region I Regional Administrator and members of the Region I staff met with senior licensee management to discuss the status of Limerick 1 and its readiness for an operating license. This meeting included a tour of the facility. Attendees included the following:

PECo

V. Boyer, Senior Vice President - Nuclear
S. Daltroff, Vice President - Electric Production
J. Kemper, Vice President - Engineering and Research
W. Ullrich, Nuclear Generation Division
G. Leitch, Station Superintendent
J. Corcoran, Field QA Branch Head

NRC

T. Murley, Regional Administrator, Region I
R. Starostecki, Director, Division of Project & Resident Programs
H. Kister, Chief, Projects Branch 2
R. Gallo, Chief, Reactor Projects Section 2A
S. Chaudhary, Senior Resident Inspector, Construction
J. Wiggins, Senior Resident Inspector, Operations

Members of the public and the local news media were present at both meetings. At each, the NRC representatives noted that more work by the NRC and the licensee would be needed prior to license issuance.

14. Additional Open Items

1) (Closed) Unresolved Item 50-352/83-19-07: Acceptability of Testing for the primary containment instrument gas (PCIG) and instrument air (IA) systems.

The inspector determined that testing had been accomplished during preoperational test 1P100.2, Loss of Instrument and Control Air, to conform with criteria 10 and 11 of Regulatory Guide (RG) 1.68.3. Additionally, the inspector noted that testing of the dessicant dryers in accordance with RG 1.68.3 criterion 3 had been added to test 1P25.1, but had yet to be performed. This action is being tracked by Test Exception 4 to 1P25.1, scheduled to be closed prior to fuel load. Regarding the air quality criterion contained in the RG, criterion 6, the licensee revised the particle size criterion to less than 50 microns. The licensee informed NRC of this change and its bases in letters to NRR dated 2/15/84 and 5/16/84. NRR has accepted the licensee's justification for exceeding the 3 micron level as will be indicated in Supplement 2 to the Safety Evaluation Report.

Completion of dessicant dryer testing is being followed by Region I in the course of routine preoperational test program inspections.

2) (Closed) IE Circular 80-07: Problems with HPCI Turbine Oil System

This IEC reported problems which had occurred at various plants involving water contamination of the stop valve oil system and failure of the seal rings in the stop valve hydraulic actuator. NRC recommended licensees examine their systems, ensure that periodically, the oil system would be checked free of water, and, that the actuator seals were routinely scheduled for examination and replacement.

The inspector verified that oil sampling will be performed after each HPCI system operation using procedures RT-5-055-570-1 and CH-501. Additionally, every 6 months, a full analysis of the oil will be conducted using RT-5-055-571-1. Hydraulic seal inspections will occur during routine preventive maintenance using PM Q-056-016. This PMQ requires routine inspection of the seals for degraded conditions. Additionally, the PMQ requires replacement of the seals every 5 years regardless of these conditions.

3) (Closed) IEB 83-03 Check Valve Failures In Raw Water Cooling Systems of Diesel Generators

This bulletin provided information about numerous incidents of failed check valves in systems important to safety and required the licensee to initiate appropriate surveillances and tests of check valves in raw water cooling systems for diesel generators. No response was required from the licensee, but the bulletin was provided as guidance in preparing the IST program. In a letter dated August 28, 1984 the licensee stated that the subject Emergency Service Water (ESW) valves will be addressed in the inservice inspection program and the diesel jacket water coolant system valves will be covered by plant maintenance procedures. The inspector reviewed the licensee's Valve Inservice Testing Program Plan and maintenance request forms to verify that the subject valves are scheduled for inspection and testing.

15. Unresolved Items

Unresolved items are matters about which more information is necessary to ascertain whether they are violations, deviations, or acceptable items. Unresolved items are discussed in paragraphs 4 and 10 of this inspection report.

16. Corrective Actions Taken As a Result of this Inspection Report

On October 2, 1984, the licensee provided those actions taken to correct the violations identified in paragraphs 2, 5 and 6 of this report and to prevent their recurrence. These actions are discussed below. The inspectors evaluated those actions taken and found them acceptable. Therefore, items 50-352/84-49-01, 03 and 04 are considered closed.

1) Temporary Change Control

The temporary change to Fuel Handling (FH) procedure 201 and the temporary change to FH-210 were reviewed by the PORC and approved by the Station Superintendent on September 13, 1984. In addition, a revision (Rev. 2), dated October 2, 1984, was made to Administrative Procedure A-3, "Procedure for Temporary Changes to Approved Procedures". This revision placed more stringent administrative controls on the initiation and processing of temporary changes.

A Temporary Procedure Change Log is to be maintained by the shift clerk. This log is designed to be a centralized record of all temporary changes and should prevent recurrence of this type of violation.

2) Design Change Control

a) The inspector reviewed Field Change Request (FCR) D389F to P&ID M-13 which corrected the drawing to show the as-built condition of the reactor enclosure head tank overflow line. Also included in the FCR was a new note to M-13 which described the preloading of the spring loaded check valve.

b) Regarding the problem with GE FCDs, GE issued FDDR-HH1-3345 to correct FCD G31-1020. Upon review of QA finding report N426, the inspector observed that the licensee had identified the cause of the problem to be associated with the implementation of the ATWS 3A modifications. In response to N426, GE reviewed all other FCDs associated with the ATWS 3A modifications and found no additional errors.

Further, the inspector noted that the licensee had implemented a program whereby Bechtel would review GE FCDs for consistency with elementary drawings, design specifications and other design documents.

17. Exit Meeting

The inspectors discussed the issues and findings in this report throughout the inspection period and at an exit meeting held with Messrs. J. Corcoran and G. Leitch on October 2, 1984. The licensee was requested to identify the issues and findings, as discussed at the exit meeting, which contained proprietary information. No items containing proprietary information were so identified.