U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-277/85-21 & 50-278/85-17

Docket No. 50-277 & 50-278

License No. DPR-44 & DPR-56

Licensee: Philadelphia Electric Company
2301 Market Street
Philadelphia, Pennsylvania 19101

Facility Name: Peach Bottom Atomic Power Station Units 2 and 3

Inspection at: Delta, Pennsylvania

Inspection conducted: May 11, 1985 - June 14, 1985

Inspectors: T. P. Johnson, Sr. Resident Inspector
J. H. Williams, Resident Inspector
S. D. Reynolds, Lead Reactor Engineer

Reviewed by: Robert M. Gallo FOR 7/3/85
J. E. Beall, Project Engineer date

Approved by: Robert M. Gallo 7/3/85
Robert M. Gallo, Chief date
DRP, Section 2A

Inspection Summary: Routine, on-site regular and backshift resident inspection (134 hours Unit 2; 114.5 hours Unit 3) of accessible portions of Unit 2 and 3, operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, refueling and outage activities, maintenance, and outstanding items.

Results: Except as noted in detail 4.1.1 regarding an apparent inattentive reactor operator, licensee activities appeared to be conducted in accordance with regulatory requirements.

DETAILS

1. Persons Contacted

   J. F. Mitman, Maintenance Engineer
   *R. S. Fleischmann, Manager, Peach Bottom Atomic Power Station
   A. A. Fulvio, Technical Engineer
   A. E. Hilsmeier, Senior Health Physicist
   D. L. Oltmans, Senior Chemist
   F. W. Polaski, Outage Planning Engineer
   S. R. Roberts, Operations Engineer
   D. C. Smith, Superintendent Operations
   S. A. Spitko, Administration Engineer
   J. E. Winzenried, Superintendent Plant Services

   Other licensee employees were also contacted.

*Present at exit interview on site and for summation of preliminary findings.

2. Plant Status

   2.1 Unit 2

   Unit 2 has been shutdown since April 28, 1984, for pipe replacement and refueling. At the beginning of this report period fuel loading was in progress. Core reload and verification were completed on May 15, 1985.

   The licensee satisfactorily completed the hydrostatic test of the Unit 2 reactor vessel and ASME class 1 attached piping on June 2, 1985. This hydrostatic test confirmed the integrity of the replaced reactor recirculation, RHR, reactor water cleanup and head spray class 1 piping in the drywell. This was also the ten year inservice inspection vessel hydrostatic test (see detail 4.4.1).

   The initial attempt at the containment integrated leak rate test (CILRT) was declared a failure by the licensee on June 9, 1985. The failure was attributed to leakage of the valve stem of AO-2502B, an isolation valve between the torus to reactor building vacuum breaker and the torus. Valve packing is not subjected to test pressure when a local leak rate test is performed. Valve packing is only tested during a CILRT. A new AO-2502B valve was installed as part of a modification during the outage. After repair of the AO-2502B valve and 5 other valves, a second CILRT was begun on June 10, 1985, and completed successfully. While at a test pressure of 49.1 psig, measured leakage was .017%/day with an allowable value for this test of less than .375%/day. On June 11, 1985, a known leakage of 4.4 scfm was superimposed on the containment to verify the test measurement system and the results were acceptable. Depressurization of the primary containment was completed on June 11, 1985. (See Inspection 277/85-23.)

The licensee satisfactorily conducted the loss of power test on June 13, 1985. This test verified that the four emergency diesel generators would automatically start and accept the emergency load within the required timing sequence.

At the end of the inspection period, the licensee's remaining work items prior to startup included maintenance jobs, I&C surveillance tests, MRF operational verifications, system check off lists and modification acceptance testing.

2.2 Unit 3

The Unit began the inspection period at 86%, limited by off-gas activity levels and extended core flow/power coastdown fuel depletion.

On May 15, 1985, the 3B reactor recirculation pump No. 1 seal failed as indicated by temperature and pressure alarms in the control room for the pump seals. The licensee instituted special periodic monitoring of the No. 2 seal and made preparations for single loop operation if the No. 2 seal were to fail. At the end of the inspection period, the No. 2 seal was operating satisfactorily.

On May 22, 1985, the Reactor Water Cleanup System (RWCU) was isolated due to a leak on the 3B RWCU pump seal. On May 24, 1985, a radioactive gaseous release occurred while attempting to return RWCU to service (see detail 4.2.2). RWCU was returned to service on May 25, 1985.

On June 4, 1985, the "A" Standby Liquid Control (SBLC) pump was declared inoperable due to a flange leak. The SBLC pump "A" was repaired and returned to service the same day (see detail 4.1.9).

On June 5, 1985, an Unusual Event was declared while Unit 3 was at 80% power due to reactor half scram, primary containment group II/III half isolations and loss of the E-23 emergency 4KV bus (see detail 4.2.4).

By June 14, 1985, the Unit had coasted down to 77% power. Current plans are to refuel in July, 1985.

3. Previous Inspection Item Update

3.1 (Closed) Inspector Follow Item 277/78-01-04. Licensed operator high school diploma conformance. The inspector reviewed A-50, Training Procedure, Revision 10, August 2, 1984, spot checked licensed operator qualification records and discussed this item with the Training Coordinator. Procedure A-50 requires implementation of

ANSI N18.1-1971 "Selection and Training of Nuclear Power Plant Personnel" with respect to high school diploma (or equivalent) requirements. The licensee utilizes NRC Form 398 which documents the high school diploma requirements. The inspector reviewed licensed operator training records (NRC Form 398), to ensure documentation was adequate for high school diploma conformance. No inadequacies were identified and the inspector had no further questions. This item is closed.

3.2 (Closed) Unresolved Item 277/81-12-04 and 278/81-10-02. Inadequate Blocking Permits. It was noted that Blocking Tags (danger tags) were obscuring component identification tags and indications. The licensee now utilizes an octagon shaped tag for hand switches. The inspector observed the use of this tag on the control room panels. No instances of obscuring component identification/indications with tags were observed. The licensee revised the corporate "Rules for Permits and Blocking" on June 1, 1984. The inspector reviewed the document along with procedure A-41, Procedure for Control of Safety Related Equipment, Revision 2, August 31, 1982 and determined them to be adequate. This item is closed.

3.3 (Closed) Inspector Follow Item 277/83-10-01. Licensed Operator Requalification Training Inadequacies. Inadequacies were identified in procedure A-50, Training Procedure regarding supplementary training for less than 80% quiz grade, required reading lists, and maintenance of exam records. The licensee revised A-50 to address these inadequacies. The inspector reviewed A-50, Revision 10, August 2, 1984. Appendix A to A-50 addresses the licensed operator requalification program. Each of three above deficient items were addressed in the revised A-50 as verified by the inspector. This item is closed.

3.4 (Closed) Unresolved Item 277/79-10-02. Automatic versus manual isolation of RHR sample line valves. As a result of IE Bulletin 79-08, the licensee performed plant modification No. 555 which provided automatic isolation of these 4 RHR lines for each unit. Unit 2 completed the modification in March, 1981 and Unit 3 in June, 1981. The inspector reviewed the completed modification package including the following items: safety evaluation, construction job memo, maintenance request forms, drawing changes, and other associated documentation and correspondence. No inadequacies were identified. This item is closed.

3.5 (Closed) Unresolved Item 278/83-27-02. Required action with torus level out of specification. Technical Specification 3.7.A.1 requires torus volume to be within the limits. T-102, Containment Control, Revision 0, 1/14/83 requires the reactor to be in hot shutdown in six hours and cold shutdown in 36 hours with torus level not within Technical Specification limits. Technical Specification 3.0.C requires similar action as above. In March, 1985, when the

torus was not within Technical Specification limits the licensee followed the requirements of Technical Specification 3.0.C and T-102. Licensee response to the March 1985 event was observed by the inspector and discussed with the licensee (see Inspection Report 278/85-08). This item is closed.

3.6 (Closed) Unresolved Item 50-277/85-04-01. In the process of making the thermal sleeve attachment weld on (N90) 90^{o} safe end a remnant of the consumable insert was left between the thermal sleeve and the nozzle/safe end weld. The NRC inspector initially reported that the remnant was discovered upon review of radiographic (RT) film of the completed nozzle/safe end weld, whereas further review indicated it was detected on the supplementary partial weld radiograph of the root of the pipe weld. The remnant was removed through the thermal sleeve attachment area as an "in process" repair. Remnant removal was verified by additional radiography. The inspector reviewed the disposition sheet indicating the remnant was removed. This item is considered resolved and is closed.

3.7 (Closed) Unresolved Item 277/84-35-03; 278/84-29-04. Inaccuracies in statements on environmental qualification of safety related electrical equipment. The licensee corrected previous inconsistent statements in a letter to NRR, dated February 5, 1985. Training on the requirements and importance of accuracy in statements made to the NRC was provided to the appropriate employees. The inspector reviewed and discussed the documentation of the training session with the licensee. Inspection Report 277/85-08 and 278/85-08 discussed the review of other aspects of the licensee's corrective actions. The inspector had no further questions. This item is closed.

4. Plant Operations Review

4.1 Station Tours

The inspector observed plant operations during daily facility tours. The following areas were inspected:

-- Control Room
-- Cable Spreading Room
-- Reactor Buildings
-- Turbine Buildings
-- Radwaste Building
-- Pump House
-- Diesel Generator Building
-- Protected and Vital Areas
-- Security Facilities (CAS, SAS, Access Control, Aux SAS)
-- High Radiation and Contamination Control Areas
-- Shift Turnover
-- Unit 2 Drywell

4.1.1 Control Room and facility shift staffing was frequently

checked for compliance with 10 CFR 50.54 and Technical Specifications. Presence of a senior licensed operator in the control room was verified frequently. During the Unit 2 containment integrated leak rate test, at about 6:15 a.m. on June 10, 1985, a regional inspector observed apparent inattentiveness on the part of the on-shift Unit 3 licensed reactor operator. (See Special Inspection Report 278/85-22.)

4.1.2 The inspector frequently observed that selected control room instruments were operable and indicated values were within Technical Specification requirements and normal operating limits. ECCS switch positioning and valve line-ups were verified based on control room indicators and plant observations. Observations included flow setpoints, breaker positioning, PCIS status, and radiation monitoring instruments.

4.1.3 Selected control room off-normal alarms (annunciators) were discussed with control room operators and shift supervision to assure they were knowledgeable of alarm status, plant conditions, and that corrective action, if required, was being taken. In addition, the applicable alarm cards were checked for accuracy. The operators were knowledgeable of alarm status and plant conditions.

4.1.4 The inspector checked for fluid leaks by observing sump status, alarms, and pump-out rates; and discussed reactor coolant system leakage with licensee personnel.

4.1.5 Shift relief and turnover activities were monitored daily, including backshift observations, to ensure compliance with administrative procedures and regulatory guidance.

4.1.6 The inspector observed main stack and ventilation stack radiation monitors and recorders, and periodically reviewed traces from backshift periods to verify that radioactive gas release rates were within limits and that unplanned releases had not occurred. (See detail 4.2.2.)

4.1.7 The inspector observed control room indications of fire detection instrumentation and fire suppression systems, monitored for proper use of fire watches and ignition source controls, checked a sampling of fire barriers for integrity, and observed fire-fighting equipment stations. No inadequacies were identified.

4.1.8 The inspector observed overall facility housekeeping conditions, including control of combustibles, loose trash and debris; and cleanup was spot-checked during and after maintenance. Plant housekeeping was generally acceptable.

4.1.9 The inspector verified operability of selected safety related equipment and systems by in-plant checks of valve positioning, control of locked valves, power supply availability, operating procedures, plant drawings, instrumentation and breaker positioning. Selected major components were visually inspected for leakage, proper lubrication, coolirg water supply, operating air supply, and general conditions. No significant piping vibration was detected. The inspector reviewed selected blocking permits (tagouts) for conformance to licensee procedures.

The "A" Standby Liquid Control (SBLC) pump was declared inoperable at 6:00 a.m., June 4, 1985, due to a pump flange leak. This placed the licensee in a 7 day action statement per Technical Specification (TS) 3.4.B.1. During routine control room monitoring on June 4, 1985, the inspector noted that the "A" SBLC pump was out of service and blocked. Also, it was noted that the "A" SBLC squib valve (11-14A) "ready light" was extinguished and the loss of squib valve continuity alarm was annunciated. The SBLC system is designed such that either pump start would fire (open) both squib valves as indicated in FSAR Section 3.8. The inspector expressed concern to the licensee shift operating personnel that only one squib valve (11-14B) was currently operable. Discussions with the licensee and a review of SBLC electrical schematics MI-S-46 sheets 1 and 2 Revision 17, indicated that both the squib valves would fire when keylock switch 11A-S1 was placed in the "start system B" position. Thus, although the loss of continuity and related alarm for the "A" squib valve was actual, the valve would still open as required when the SBLC initiate switch 11A-S1 was placed in the "start system B" position. The inspector verified this by reviewing MI-S-46 sheets 1 and 2, and had no further questions. The inspector reviewed TS 3.4.B.1 and 4.4.B.1 for SBLC system requirements. The inspector verified that the licensee tested the operable SBLC pump B by reviewing completed surveillance test ST-6.1.1, Daily Standby Liquid Control Pump Functional Test, Revision 1, November 11, 1983, performed on June 4, 1985. The "A" SBLC pump flange leak was repaired, the system was tested satisfactorily, declared operable and returned to service at 8:00 p.m. on June 4, 1985. Within the scope of this review, no unacceptable conditions were identified.

4.2 Followup On Events Occurring During the Inspection

4.2.1 Unit 2 Scram During Hydrostatic Test

Unit 2 auto scrammed on reactor high pressure at 4:36 p.m. on May 30, 1985, while performing the hydrostatic test

procedure GP-10-2, Revision 14, May 21, 1985. Prior to the scram, the unit was in cold shutdown, with all control rods inserted, maintaining reactor temperature at 185°F and reactor pressure at approximately 1000 psig. Control rod scram time testing had been completed on one rod and excess flow check valve testing was in progress. The scram signal occurred at 1030 psig. The Technical Specification limit is less than or equal to 1055 psig.

The cause of the reactor pressure increase and resultant scram signal was evaluated by the licensee as follows. Reactor pressure was being maintained in accordance with GP-10-2. The reactor water level was greater than 350 inches instrument reference, i.e., the vessel was full. The control rod drive hydraulic pump was supplying the hydro pressure; and, pressure control was established by throttling the reactor water cleanup (RWCU) reject flow. A high flow (about 5 liters per minute) from the reactor recirc pump seal purge excess flow check valve testing was stopped concurrent with the Unit 2 reactor operator closing the RWCU reject valve. Both these actions caused a reactor pressure increase and resulted in the auto scram signal.

The inspector reviewed the reactor pressure trace, discussed the event with Unit 2 operator and with the shift supervision, and reviewed plant logs. The reactor protection system (RPS) functioned as required to give a full automatic scram on both channels. The inspector verified that the reactor scrammed at a pressure of 1030 psig and discussed this with the licensee. The licensee stated that it was normal to set the scram setpoint about 20 psig less than the Technical Specification limit of 1055 psig to account for possible instrument inaccuracies and setpoint drift. The inspector had no further questions.

The licensee reset the scram and regained reactor pressure control at 1000 psig in accordance with procedure GP-10-2. A four hour report was made via the ENS as required by 10 CFR 50.72.

4.2.2 Unit 3 Gaseous Radioactive Release

Unit 3 experienced a gaseous radioactive release at 12:35 a.m. on May 24, 1985, while attempting to return the Reactor Water Cleanup system (RWCU) to service. RWCU had been out of service since May 22, 1985, due to a RWCU pump seal leak. The reactor building radiation monitor alarmed during the attempt to return RWCU to service. The radiation monitor recorder (RR 3979) channel A trace spiked at a level of 50,000 counts per minute (cpm) and channel B

trace spiked at a level of just less than 40,000 cpm. The licensee's emergency plan implementing procedure EP-101, Classification of Emergencies, Revision 10, required declaration of an Unusual Event for an instantaneous release exceeding Technical Specification limits or if the reactor building ventilation radiation monitor reading is greater than 40,000 cpm on RR 3979. The licensee did not declare an Unusual Event because the release was calculated to be 15.2% of the Technical Specification whole body limit.

The inspector discussed the event with the licensee and expressed concern regarding the non-specificity of the implementation criteria of EP-101. EP-101 details the control room recorder level setpoints for the main stack and reactor building vent stack radiation monitors for which an Unusual Event should be declared for a release exceeding Technical Specification instantaneous limits. The licensee agreed that EP-101 did not provide specific detailed implementation criteria and revised the procedure by 4:30 p.m. on May 24, 1985. The inspector reviewed the EP-101, Revision 11, and determined it to be adequate. The revised EP-101 specifies that an Unusual Event be declared if a gaseous release exceeds TS 3.8.C.1 limits, which may be indicated by exceeding certain radiation monitor setpoints. The inspector reviewed the implementation of the revised EP-101 in the control room, reviewed the setpoint levels for the main stack and reactor building vent radiation monitors, and discussed the revised procedure with control room personnel. Based on this review and discussions, the inspector determined that newly revised EP-101, Revision 11 was adequate.

The cause of the gaseous release was due to a failed relief valve on the RWCU regenerative heat exchanger. The inspector observed licensee actions in determining the source of this leak on May 24, 1985, from the control room and locally in the reactor building. The licensee repaired the relief valve and returned RWCU to service on May 25, 1985.

On May 29, 1985, the inspector discussed this release and licensee actions regarding Unusual Event classification criteria with the Manager, PBAPS. The Manager, PBAPS, stated that he and the Shift Superintendent had discussed the release over the phone shortly after it occurred on May 24, 1985. An Unusual Event was not declared based on the following:

-- The release did not exceed the TS 3.8.C.1 limit for gaseous releases (15.2% of TS limit as calculated).

-- The source of the release was known to be the RWCU system and RWCU was isolated.

-- The plant was not in an accident condition.

-- The release was instantaneous as indicated by the control room traces (reactor building radiation monitor).

The inspector concurred with the licensee's analysis and decision process, and had no further questions. (Inspection Report 277/85-24; and 278/85-20 further discusses and analyzes this event.)

4.2.3 <u>10 CFR 21 Report Regarding the Emergency Diesel Generators</u>

On May 29, 1985, the inspector was informed of a diesel generator problem at Calvert Cliffs. The problem concerns a Colt Industries supplied generator where an interconnecting bar (ferry ring) between adjacent poles on the generator rotor broke off during a diesel generator test on May 14, 1985, and damaged the generator stator. The failure mechanism was evaluated as fatigue cracking of the ferry ring. The generator vendor was notified and subsequently, on May 21, 1985, a 10 CFR 21 report was made. The vendor is Louis Allis (formerly Colt Industries) and a preliminary determination was that the ferry rings are not necessary and therefore were removed at Calvert Cliffs.

Peach Bottom utilizes a similarly designed generator supplied by Colt Industries (current vendor is Louis Allis). The inspector notified the licensee of the event at Calvert Cliffs on May 29, 1985, and on May 31, 1985, of the 10 CFR 21 report. The licensee stated that they had been informed via a phone call from Calvert Cliffs on May 28, 1985, regarding the potential generator problem. On June 6, 1985, the licensee received an INPO notepad report regarding the event at Calvert Cliffs and corrective action taken. The licensee is currently evaluating this event and intends to inspect the interconnecting bars for the E-2 diesel generator on June 17, 1985. Additional inspections and maintenance (ST 8.1.4, Diesel Generation Inspection) is scheduled in July, 1985. The licensee has contacted the vendor and other utilities with the similarly designed diesel generator. Licensee representatives observed the removal of interconnecting bars at TMI Unit 1. The inspector will observe licensee inspection of the E-2 diesel generator interconnecting bars and review the corrective actions. (IFI 277/85-21-01.)

4.2.4 Unit 3 Unusual Event

At 11:55 a.m., on June 5, 1985, with Unit 3 at 80% power, a reactor half scram and primary containment group II and III outboard half isolation occurred. The cause of the event was determined by the licensee to be an operator closing a breaker compartment door on emergency 4 KV bus E-23, resulting in the energization of the E-23 overcurrent bus protection and lockout relays. These relays caused a breaker trip and lockout for the Unit 2 startup and emergency feeder breaker E-223 (152-1608), resulting in a fast transfer of the E-23 bus to its alternate feed from the Unit 3 startup and emergency feeder breaker E-323 (152-1601). The fast transfer caused a momentary loss of power to the E-234 emergency load centers and motor control centers, causing a loss of 120 VAC panel 30Y34. Panel 30Y34 supplies power to the outboard isolation valve relays and loss of 30Y34 caused the half isolation of primary containment group II/III. The licensee determined that the half scram was due to MSIV 86C drifting shut from loss of power to the AC pilot solenoid and apparent failure of the DC pilot solenoid concurrent with the existing status of the reactor protection system with an inoperable limit switch for the MSIV 80A (see Inspection 278/85-12, detail 4.2.1). The RPS is aligned so that closure of either MSIV 80C or 86C would give an auto scram channel B.

The licensee reset the half scram and the half outboard group II and III primary containment isolations. During the investigation, the licensee determined that one of the overcurrent bus protection and lockout relays (186-BX-16) failed to function correctly. This relay trips and locks out breakers for Unit 3 startup and emergency feeder breaker E-323 "B" RHR pump, "A" control rod drive hydraulic pump, "B" core spray pump and emergency loader E234. If this relay had operated correctly during the event, E-23 bus should have de-energized resulting in an E-2 diesel generator start and loading.

The licensee developed a special procedure, SP-810, Checkout of Relays 186-BX-16/186-BY-16, Revision 0, to test both of these overcurrent and lockout relays. In order to implement the test, the E-23 bus was declared inoperable which placed the licensee in a TS 3.5.A.7 action statement requiring a plant shutdown due to loss of both the "B" core spray and "B" RHR pumps. At 3:55 p.m. on June 5, 1985, the licensee declared an Unusual Event and the NRC was notified via the ENS in accordance with 10 CFR 50.72. The special procedure, SP-810, determined that both overcurrent relays were operable, the licensee returned the E-23 bus to

service, and declared the Unusual Event terminated at 4:01 p.m.

The inspector reviewed the special procedure to test the relays, SP-810, prior to its implementation and observed the test from the control room. The licensee implemented the procedure satisfactorily and took the necessary precautions. The notification of Unusual Event was observed from the control room by the inspector, including termination. The licensee commenced load reduction as required by TS 3.5.A.7 due to concurrent inoperability of "B" RHR and "B" core spray pumps. The inspector reviewed the completed special procedure SP-810 for adequacy and completeness. The inspector reviewed control room traces, the event data logger and interviewed control room operators after the event. The inspector confirmed that the event initiated when the E-223 breaker opened at 11:55:32 a.m. on June 5, 1985. The inspector noted that the auto half scram occurred about 1 second later, caused by a MSIV not full open trip on RPS channel B. The scram was reset at 11:55:54 a.m., or about 22 seconds after event initiation. The licensee determined the cause of MSIV 86C partial closure was the de-energization of its AC pilot solenoid caused by loss of power during the E-23 bus fast transfer together with its faulty DC pilot solenoid that was already de-energized. The MSIVs will auto close on loss of power to both the AC and DC pilot solenoids. The licensee is investigating the faulty pilot solenoid for the MSIV 86C.

Within the scope of the review of this event, no unacceptable conditions were identified.

4.3 Logs and Records

The inspector reviewed logs and records for accuracy, completeness, abnormal conditions, significant operating changes and trends, required entries, operating and night order propriety, correct equipment and lock-out status, jumper log validity, conformance to Limiting Conditions for Operations, and proper reporting. The following logs and records were reviewed: Shift Supervision Log, Reactor Engineering Log, Reactor Operator's Log (Unit 2), Reactor Operator's Log (Unit 3), Control Operator Log Book and STA Log Book, Night Orders, Radiation Work Permits (RWP's), Maintenance Request Forms and Ignition Source Control Checklists. Control Room logs were compared against Administrative Procedure A-7, "Shift Operations". Frequent initialing of entries by licensed operators, shift supervision, and licensee on-site management constituted evidence of licensee review. No unacceptable conditions were identified.

4.4 Refueling/Outage Activities

4.4.1 Unit 2 Hydrostatic Test

On June 2, 1985, the licensee satisfactorily completed the hydrostatic test of the Unit 2 reactor vessel and ASME class 1 attached piping in accordance with GP-10-2, Revision 14. This hydrostatic test confirmed the integrity of the replaced reactor recirculation, RHR, reactor water cleanup and head spray class 1 piping in the drywell. This was also the ten year inservice inspection vessel hydrostatic test. After four hours at hydro test pressure, an inspection was performed of all class 1 pressure retaining components.

Prior to the hydrostatic test, the inspector reviewed the following documentation:

-- GP-10-2, Operational Hydrostatic Test - Unit 2, Revision 14, 05/21/85

-- GP-10-2A, Hydrostatic Test Procedure, Revision 3, 06/18/84

-- GP-10-2-A, Hydro Valve Line Up - Unit 2, COL, Revision 2, 06/18/84

-- GP-10-2-1, Hydro Test Instrumentation Unit 2, COL, Revision 4, 04/26/76

-- GP-10-2-2, Valve Shaft Seal Leakoffs - Unit 2 Only, COL, Revision 7, 05/21/85

-- GP-10-2-3, Operation Hydro Valve Lineup - Unit 2, COL, Revision 9, 05/21/85

-- GP-10-2-3.1, Operation Hydro Main Steam Valve Line Up - Unit 2, COL, Revision 0, 05/21/85

-- GP-10-2-4, Leak Inspection - Unit 2 Only, COL, Revision 7, 10/13/82

Prior to the reactor vessel pressurization and during the hydro test the inspector reviewed plant conditions including Technical Specification temperature and pressure requirements (TS 3.6A and 4.6A). Reactor water temperature was maintained greater than the minimum temperature of 120°F allowed for hydro testing per Technical Specification Figure 3.6.1, as verified by the inspector. Also, reactor vessel temperature and pressure were logged every 15 minutes as required by TS 4.6.A.1,2, and 3 as verified frequently by the inspector.

The inspector reviewed the associated test documentation during progress of the test. Procedural steps and completed COL signoffs were verified to be correct and complete.

While at the hydro test pressure of 1050-1059 psig, the inspector monitored reactor pressure closely. The inspector verified that reactor pressure was maintained at the required hydro pressure as indicated on control room recorder PR-6-97, on computer point B013, on local gauges PI-60A and B, and on a temporary gauge installed on the top of the scram discharge instrument volume. The inspector noted that local gauges PI-60A and B at instrument racks C65A and B had calibration stickers dated April 11, 1985 and April 1, 1985. The hydro procedure, GP-10-2, requires these gauges to be calibrated within 2 weeks of hydro inspections (performed May 29 and June 2, 1985). The hydro procedure had the calibration date listed as May 21, 1985, for the two gauges PI-60A and B. The inspector asked the licensee whether the April 1 and 11, 1985 dates on the calibration stickers or the May 21, 1985 dates on the procedure signoff were correct. The licensee stated that the May 21, 1985 dates were correct and that the calibration stickers were in error. The inspector verified this to be correct.

While the reactor vessel was pressurized at 1000 psig on May 30, 1985, the inspector performed a Unit 2 drywell inspection. Items noted included the following:

-- small packing leaks on several valves

-- main steam safety relief valves RV71G and H leaking

-- mirror insulation off a number of pipes and components

The inspector discussed these items with the licensee. The licensee had also noted these conditions and documented them. Maintenance request forms (MRF) were issued for the leaks and the licensee intends to correct them prior to startup.

During implementation of the hydro test, an unplanned full reactor scram occurred during a pressure excursion (see detail 4.2.1). Also, during the hydro test, ST 13.8-1, Excess Flow Check Valve Operability, was performed (see detail 7).

Within the scope of this hydrostatic test review, and excluding the above mentioned deficiencies, no unacceptable conditions were identified.

4.5 Engineered Safeguards Features (ESF) System Walkdown

The inspector performed a detailed walkdown of portions of the Control Room Emergency Ventilation system in order to independently verify the operability of the Unit 2 and 3 common system. The system walkdown included verifications of the following items:

-- Inspection of system equipment conditions.

-- Confirmation that the system check-off-list (COL) and operating procedures are consistent with plant drawings.

-- Verification that system valves, breakers, dampers, and switches are properly aligned.

-- Verification that instrumentation is properly valved in and operable.

-- Verification that valves required to be locked have appropriate locking devices.

-- Verification that control room switches, indications and controls are satisfactory.

-- Verification that surveillance test procedures properly implement the Technical Specifications surveillance requirements.

Documentation reviewed for the Control Room Emergency Ventilation system is included in Attachment 1.

Within the scope of this system walkdown and the reviews conducted, no inadequacies were identified.

5. Event "V"

As part of a special inspection regarding potential overpressurization of Emergency Core Cooling Systems (Event V), the inspector reviewed drawings, procedures, and operating and maintenance information associated with the boundary and isolation of the high/low pressure piping. Numerous discussions were held with the licensee on the subject.

By review of P&ID's (M-359, M-361, M-362, and M-365), the inspector identified the design pressure and temperature of the system piping, noting the boundaries between high and low pressure pipe and the isolation valves in the lines. The procedures for testing these

isolation valves were reviewed and discussed with the licensee with respect to prevention of overpressurization of the low pressure piping. A review was also made of the frequency and type of corrective and

preventive maintenance done on these isolation valves. Discussions were held with Quality Control personnel on their involvement with maintenance activities associated with these isolation and air-operated check valves. The inspector reviewed post operating experience and discussed this experience with the licensee to determine if any overpressurization events had occurred at Peach Bottom. None had occurred.

Licensee actions to protect against overpressurization events included:

-- Review of operating experience in the industry and consideration of how the experience applies to Peach Bottom.

-- Relief valves in the low pressure line.

-- LLRT performed after valve maintenance.

-- Maintenance procedures written for specific valves.

-- Post maintenance testing required.

-- Design logic which closes one of two isolation valves in pump discharge line when system is tested.

Documentation reviewed for this inspection is listed in Attachment 2.

The inspector concluded that within the scope of this review, no unacceptable conditions were noted.

6. Review of Licensee Event Report (LER)

The inspector reviewed the following LER submitted to NRC:RI to verify that the details were clearly reported, including the accuracy of the description and corrective action adequacy. The inspector determined whether further information was required, whether generic implications were indicated, and whether the event warranted on-site followup.

LER No. LER Date Event Date	Subject
2-85-01 R1 January 8, 1985 May 9, 1985	Exceeding Local Leak Rate Test Allowable Limit

7. Surveillance Testing

The inspector observed surveillance tests to verify that testing had been properly scheduled, approved by shift supervision, control room operators were knowledgeable regarding testing in progress, approved procedures were being used, redundant systems or components were available for service as required, test instrumentation was calibrated, work was performed by qualified personnel, and test acceptance criteria were met. Parts of the following tests were observed:

-- ST-9.12, Reactor Vessel Head Flange Temperature Surveillance, Rev. 0, 9/1/83, performed on May 22, 1985

-- ST-13.8-1, Unit 2 Excess Flow Check Valve Operability, Rev. 4, 5/28/85, performed on May 30, 1985

-- ST-12.5, Unit 2 Integrated Leak Rate Test, Rev. 3, 6/6/85, performed on June 10 and 11, 1985.

In addition, a review of the following completed surveillance test was performed:

-- ST-6.1.1, Daily Standby Liquid Control Pump Functional Test, Rev. 1, 11/11/83, performed on June 4, 1985.

No unacceptable conditions were noted.

8. Maintenance

For the following maintenance activities the inspector spot-checked administrative controls, reviewed documentation, and observed portions of the actual maintenance:

Maintenance Procedure/ Document	Equipment	Date Observed
M-4.42	Electrical Heating of Reactor Vessel Head	May 20, 1985
M-4.65	Installation of Reactor Vessel Head	May 22, 1985
M-4.3	Closing the Reactor Vessel	May 22, 1985

Administrative controls checked included maintenance requests, blocking permits, fire watches and ignition source controls, item handling reports, and shift turnover information. Documents reviewed included procedures, material certifications and receipt inspections, welder qualifications and weld information data sheets.

No unacceptable conditions were identified.

9. Radiation Protection

During this report period, the inspector examined work in progress in both units, including the following:

-- Health Physics (HP) controls

-- Badging

-- Protective clothing use

-- Adherence to RWP requirements

-- Surveys

-- Handling of potentially contaminated equipment and materials

The inspector observed individuals frisking as required by Health Physics procedures. A sampling of high radiation doors was verified to be locked as required. Compliance with RWP requirements was verified during each tour. Line entries were reviewed to verify that personnel had provided the required information and people working in RWP areas were observed to be meeting the applicable requirements. No inadequacies were identified.

10. Physical Security

The inspector monitored for compliance with the accepted Security Plan and associated implementing procedures, including: operations of the CAS and SAS, checks of vehicles on-site to verify proper control, observation of protected area access control and badging procedures on each shift, inspection of physical barriers, checks on control of vital area access and escort procedures. No inadequacies were identified.

11. Inspector Follow Items

Inspector follow items are items for which the current inspection findings are acceptable, but due to on-going licensee work or special inspector interest in an area, are specifically noted for future follow-up. Follow-up is at the discretion of the inspector and regional management. An inspector follow item is discussed in detail 4.2.3.

12. Management Meetings

12.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the Station Superintendent at the conclusion of the inspection. During the inspection, licensee management was periodically notified verbally of the preliminary findings by the resident inspectors. No written inspection material was provided to the licensee during the inspection. No proprietary information is included in this report.

12.2 Attendance at Management Meetings Conducted by Region-Based Inspectors

The resident inspectors attended entrance and exit interviews by region-based inspectors and other meetings as follows:

Date	Subject	Inspection Report No.	Reporting Inspector
May 24	Tech Spec Meeting with RI, NRR and PECo	None	T. Collins (NRR)
May 30 (Ent) May 31 (Exit)	NRC Licensing Exam for Fuel Handling SLOs	278/85-18	D. Lange
June 4 (Ent) June 13 (Exit)	ILRT	277 & 278/85-23	D. Florek
June 11 (Ent) June 14 (Exit)	Emergency Planning	277/85-24 278/85-20	J. Hawxhurst
June 12	SALP Management Meeting	277 & 278/85-99	R. Gallo

ATTACHMENT 1

Control Room Ventilation System Documentation Reviewed

-- FSAR sections 10.13 and 7.12.5

-- TS 3.11.A/4.11.A

-- ST-9.8, Control Room Emergency Ventilation and Radiation Monitor Functional Test, Revision 10, 5/18/84

-- P&ID M-393, Control Room Ventilation Flow Diagram, Revision 10, 2/26/85

-- P&ID M-384, Control Room Temperature Control Diagram, Revision 19, 6/16/80

-- P&ID M-328, Cooling & Heating Piping Systems, Revision 14, 11/30/76

-- P&ID M-334, Ventilation Radiation Monitoring System, Revision 15, 10/31/83

-- S.12.6.2.A, Normal Operation of the Control Room Ventilation, Revision 0, 01/18/73

-- S.12.6.2.A, COL, Control Room Radiation Monitor Sample Station Check List, Revision 0, 08/30/82

-- S.12.6.2.B, Setup of Control Room Emergency Vent System for Automatic Operation, Revision 1, 07/31/75

-- S.12.6.2.C, Control Room Purge Air System, Revision 0, 01/18/73

-- S.12.6.2.D, Routine Inspection of Control Room Ventilation System, Revision 1, 07/31/75

-- S.12.6.1.A, Aligning the Control Room Chilled Water System Valving in Preparation for Control Room Chiller Startup, Revision 0, 11/16/72

-- S.12.6.1A, COL, Control Room Chilled Water Startup, Revision 3, 06/18/80

-- S.12.6.1.B, Starting Up the Control Room Chilled Water System Normal Operation, Revision 0, 11/16/72

-- S.12.6.1.D, Loss of the Control Room Chiller Units and/or the Control Room Chilled Water Pumps, Revision 1, 06/24/80

-- S.12.6.1.E, Chemical Addition to the Control Room Chilled Water System, Revision 1, 06/17/80

-- S.12.6.1.F, Routine Inspection - Control Room Chiller Operating, Revision Revision 0, 10/29/80

ATTACHMENT 2

Procedures and Drawings Reviewed for Event V Inspection

Drawings: M-359 Rev 18, Reactor Core Isolation Cooling System, Sheets 1 and 2
M-361, Rev 27, Residual Heat Removal System, Sheets 1 and 2
M-362, Rev 25, Core Spray Cooling System, Sheets 1 and 2
M-365, Rev 23, High Pressure Coolant Inspection System, Sheets 1 and 2

Surveillance Tests

ST 1.4, Rev 16, Core Spray "A" Logic System Functional
ST 1.6, Rev 14, RHR Logic "A" System Functional Test
ST 6.6, Rev 21, Core Spray "A" Pump Valve, Cooler Functional (Unit 3 Only)
ST 6.6.1, Rev 6, Daily Core Spray "A" System and Cooler Operability (Unit 3 Only)
ST 6.6.F, Rev 2, Core Spray "A" Pump, Valve, Flow, Cooler-Flow Test (Unit 3 Only)
ST 6.8, Rev 24, RHR "A" Pump, Valve, Flow and Unit Cooler Functional
ST 6.8.1, Rev 13, Daily RHR "A" System and Unit Cooler Operability
ST 6.18, Rev 4, ISI-Normally Closed Valve Testing
ST 11.5, Rev 9, PCIS Simulated Automatic Actuation Test
ST 20.041, Rev 5, LLRT RHR Shutdown Cooling Pump Suction
ST 20.042, Rev 3, LLRT RHR "B" Pump Discharge
ST 20.042-1, Rev 3, LLRT RHR "B", MO-10-25B
ST 20.042-2, Rev 2, LLRT RHR "B", MO-10-154B, SV-4222
ST 20.043, Rev 3, LLRT RHR "A" Pump Discharge
ST 20.045, Rev 3, LLRT Core Spray "B" Loop MO-11B Test with Rx Pressurized
ST 20.045-1, Rev 3, LLRT Core Spray "B" Loop
ST 20.046, Rev 4, LLRT Core Spray "A" Loop MO-11A Test with Rx Pressurized
ST 20.046-1, Rev 3, LLRT Core Spray "A" Loop
ST 20.047, Rev 4, LLRT-RPV Head Spray

Routine Tests

RT 14.10.13A, Rev 0, MO-10-13A Outgoing Interlocks
RT 14.10.15A, Rev 0, MO-10-15A Outgoing Interlocks
RT 14.10.17, Rev 1, MO-10-17 Outgoing Interlocks Test
RT 14.10.18, Rev 1, MO-10-18 Outgoing Interlocks Test
RT 14.10.25A, Rev 0, MO-10-25A Post Maintenance Interlock Check
RT 14.10.32, Rev 0, MO-2(3)-10-32 Outgoing Interlocks Test
RT 14.10.33, Rev 0, MO-2(3)-10-33 Outgoing Interlocks Test
RT 14.10.154A, Rev 0, MO-10-154A Post Maintenance Interlock Check
RT 14.14.11B, Rev 0, MO-14-11B Outgoing Interlock Test

Maintenance Procedures

M-5.1, Rev 2, Visual Inspection of Valves
M-9.1, Rev 11, Limitorque Switches Inspection, Maintenance, Adjustment, Lubrication
M-9.3, Rev 1, Disassembly and Repair of Limitorque Valve Operators

M-10.3, Rev 3, Residual Heat Removal (RHR) MO-1564A&B Valve Maintenance (MARK-RA-123WSP)
M-10.31, Rev 1, Residual Heat Removal (RHR) 24" AO-10-46 Injection Check Valve Maintenance (MARK 214M3)
M-10.36, Rev 0, Residual Heat Removal (RHR) 10-81 Gate Valves Maintenance (MARK N10LWSP)
M-13.10, Rev 1, RCIC Testable Check Valve AO-13-22
M-14.10, Rev 0, Core Spray -12" AO-14-13A&B Testable Check Valve
M-14.2, Rev 4, Core Spray 12" MO-14-11 & MO-14-12 Gate Valve Maintenance (MARK 12-R14WSP)
M-23.25, Rev 0, HPCI Testable Check Valve (AO-23-18)

Administrative Procedures

MA-9, Rev 4, Procedure for Training and Testing of Maintenance Division Personnel
A-25, Rev 2, Preventive Maintenance Program
A-26, Rev 24, Procedure for Corrective Maintenance
A-26A, Rev 2, Procedure for Corrective and Preventive Maintenancw Using CHAMPS
A-27, Rev 13, Procedure for Material Control System
A-50, Rev 10, Training Procedure