ENCLOSURE 1

SALP BOARD REPORT

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE

INSPECTION REPORT 50-277/85-98 and 50-278/85-98

PHILADELPHIA ELECTRIC COMPANY

PEACH BOTTOM ATOMIC POWER STATION

ASSESSMENT PERIOD - APRIL 1, 1985 TO JANUARY 31, 1986

BOARD MEETING DATES MARCH 24 AND APRIL 22, 1986

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I. INTRODUCTION

1.1 Purpose and Overview

The Systematic Assessment of Licensee Performance (SALP) is an integrated NRC staff effort to collect the available observations and data on a periodic basis and to evaluate licensee performance based upon this information. SALP is supplemental to normal regulatory processes used to ensure compliance to NRC rules and regulations. SALP is intended to be sufficiently diagnostic to provide a rational basis for allocating NRC resources and to provide meaningful guidance to the licensee's management to promote quality and safety of plant construction and operation.

An NRC SALP Board, composed of the staff members listed below, met on March 24 and April 22, 1986, to review the collection of performance observations and data and to assess the licensee performance in accordance with the guidance in NRC Manual Chapter 0516, "Systemmatic Assessment of Licensee Performance." A summary of the guidance and evaluation criteria is provided in Section II of this report.

The following report is the SALP Board's assessment of the licensee's performance at the Peach Bottom Atomic Power Station for the period April 1, 1985 through January 31, 1986.

1.2 SALP Board Members

R. W. Starostecki, Director, Division of Reactor Projects (DRP)
W. F. Kane, Deputy Director, DRP
T. T. Martin, Director, Division of Radiation Safety and Safeguards
S. D. Ebneter, Director, Division of Reactor Safety (DRS)
S. J. Collins, Chief, Projects Branch No. 2, DRP
R. M. Gallo, Chief, Reactor Projects Section 2A, DRP
D. R. Muller, Director, BWR Project Directorate #2, NRR
G. E. Gears, Licensing Project Manager, NRR
T. P. Johnson, Senior Resident Inspector, Peach Bottom
R. R. Bellamy, Chief, Emergency Preparedness and Radiological Protection Branch
L. H. Bettenhausen, Chief, Operations Branch, DRS

Other NRC Attendees

J. E. Beall, Project Engineer, RPS 2A, DRP
J. H. Williams, Resident Inspector, Peach Bottom
J. P. Rogers, Reactor Engineer, RPS 2A, DRP
J. R. Johnson, Chief, Operational Programs, DRS
W. V. Johnston, Deputy Director, DRS
D. J. Sullivan, Operating Reactors Programs Branch, IE

1.3 Background

Peach Bottom Units 2 and 3 were issued operating licenses on October 25, 1973 (DPR-44) and July 2, 1974 (DPR-56), respectively. Unit 2 began commercial operation during July 1974, and Unit 3 began commercial operation during December 1974.

1.3.1 Licensee Activities

(1) Unit 2 Status

Unit recovery, from the pipe replacement outage and refueling, was in progress at the beginning of the assessment period. Fuel loading began May 2, 1985, and reload verification was completed on May 15, 1985. The hydrostatic test was satisfactorily completed for the Unit 2 reactor vessel and ASME class 1 attached piping on June 2, 1985.

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 valve stem leakage of AO-2502B, an isolation valve between the torus to reactor building vacuum breaker and the torus. After repairs, a second CILRT was begun on June 10, 1985, and completed successfully.

On July 6, 1985, the licensee commenced reactor startup and at 4:00 p.m., the reactor was critical. As power was increased two intermediate range monitors (IRM) were declared inoperable, and the licensee inserted a half scram and shut down the reactor. The two IRM detectors were replaced and tested satisfactorily. The reactor was restarted on July 7, 1985, and startup testing commenced. The unit was synchronized with grid on July 13, 1985.

Unit 2 was shut down on July 18, 1985, due to turbine high vibration. The unit was restarted on July 19, 1985, after turbine balancing and repair of the "B" reactor feedwater pump. On July 22, 1985, Unit 2 was shut down to repair a leak on the "C" reactor feedwater pump discharge line instrument tap. The unit was restarted on July 24, 1985, after repairs.

Load reductions occurred during July 1985 as follows: on July 27, 1985, for a control rod pattern adjustment; on July 30, 1985, after the main steam line radiation levels increased as a result of an apparent resin injection into the reactor vessel; and, on July 31, 1985, to repair the "A" reactor feedpump turbine exhaust rupture disc.

Power ascension continued and the unit achieved 100% power on August 2, 1985. On August 5, 1985, the unit scrammed from 100% during turbine control valve testing. The unit restarted, and on August 7, 1985, a scram on the IRM high flux occurred. The unit was restarted on August 8, 1985.

On August 12, 1985, and again on August 19, 1985, the unit was shutdown due to an inoperable diesel generator and one RHR loop. A reactor scram occurred during the restart on August 26, 1985, while placing a reactor pressure transmitter in service. The unit was restarted the same day. On August 29, 1985, a recirculation pump trip test was performed satisfactorily to test the dynamic loads on the new recirculation system piping.

The unit was removed from service on September 19, 1985, due to deteriorating performance of the 2A RHR pump, coincident with the E-2 diesel generator being out-of-service. The unit remained shutdown until October 4, 1985, when unit startup was effected. The unit achieved 100% power on October 6, 1985.

The unit remained at 100% power until October 17, 1985, when Unit 2 scrammed on low reactor water level due to loss of feedwater. The unit was restarted on October 18, 1985, and achieved 100% power on October 19, 1985. Load reductions occurred on October 6 and 20, 1985, to adjust control rod patterns.

On November 10, 1985, a cable tray fire in the Radwaste Building occurred. On November 29, 1985, during a scheduled plant shutdown for maintenance, the unit scrammed from 33% power during turbine stop valve troubleshooting. The unit remained in cold shutdown until December 24, 1985. Activities during this shutdown included RHR pump inspections, mechanical snubber changeout, equipment environmental qualification modifications and preventive

maintenance, and testing. The 2A, 2C and 2D RHR pumps were inspected and repaired with replacement impellers and wear rings.

On December 24, 1985, the unit restarted and on December 26, 1985, the unit scrammed from 44% reactor power during reactor feedwater pump swapping and level control system troubleshooting. During feedwater pump swapping, a feedwater hammer transient caused a feedwater leak on the feedwater pump suction piping. The unit restarted on December 29, 1985.

The unit scrammed on January 1, 1986, from 90% reactor power due to a main turbine trip caused by a moisture separator high level. The unit was restarted on January 2, 1986.

On January 14, 1986, the unit was shut down to repair main condenser tube leaks, two IRMs, reactor feed pump minimum flow valves and the C1 condenser water box inlet valve. During the startup on January 18, 1986, the unit experienced three drifting control rods. The unit returned to service on January 19, 1986.

The unit scrammed from 95% reactor power on January 24, 1986, due to an E-2 diesel generator (DG) trip and MSIV closure. Inspection of E-2 DG revealed damage to the scavenging air blower and to the turbo-chargers. The unit remained shut down through the remainder of the assessment period while the E-2 DG was being repaired.

(2) Unit 3 Status

The unit began the assessment period at 90% reactor power, limited by off-gas activity levels and end of core life fuel depletion. Unit 3 implemented cycle 6 extended core flow operations and remained in this coastdown mode operating condition until shutdown for refueling.

On April 10, 1985, during core spray system logic testing, two emergency diesel generators started. Operators decreased reactor power to 50% in anticipation of a possible transient; however, plant recovery was effected, and power was returned to 90%.

Reactor power had coasted down to 87% by April 20, 1985; and power was reduced to 50% to remove the fifth stage feedwater heaters from service in accordance with the extended core flow procedure. Reactor power was then returned to 90%.

On May 12, 1985, load was reduced to 41% power to accommodate control rod pattern adjustment and main steam isolation valve closure time testing. On May 15, 1985, the inner seal on the 3B recirculation pump failed. Power was reduced to 81% until May 17, 1985, in an effort to determine if pump speed and seal performance were related. No change in seal performance occurred. The operating seal parameters were monitored with no signs of deterioration.

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

Load was reduced on June 20, 1985, to investigate a vacuum leak and repair the 3A recombiner compressor. The leak was determined to be caused by a ruptured tube in the main condenser B1 waterbox. On June 23, 1985, the power increase was halted when reactor conductivity increased to 0.9 micromho/cm. Power was reduced to leak check the condenser waterboxes. The leak was repaired by plugging condenser tubes and power was then increased.

On July 9, 1985, a personnel accident associated with the cooling tower transformer caused an initiation of one of two automatic logic signals for the Group II and III containment isolation, and loss of various electrical loads, including the Unit 3 recombiner compressor and air ejector.

The licensee began shutting down Unit 3 on July 14, 1985, for its sixth refueling outage. The licensee shut down and depressurized slowly because of relatively high coolant activity levels and the potential for gaseous radioactive releases from system perturbations. The reactor vessel disassembly began on July 26, 1985.

During the refueling outage the following items were accomplished:

-- Reactor core defueling and refueling

-- Fuel inspections, sipping and reconstitution of 101 bundles due to some leaking fuel rods
-- Control rod drive exchange
-- IRM/SRM dry tube replacements due to cracking in the upper spring region
-- Recirculation and RHR piping NDE inspections (reference Generic Letter 84-11) and weld overlays
-- Core spray sparger T-box repairs due to cracking at the junction box
-- Recirculation suction piping nozzle (N-1) plug sample
-- 10 CFR 50 Appendix R, Alternate Safe Shutdown modifications
-- Emergency Service Water System modifications
-- 125 VDC battery replacements
-- Emergency diesel generator annual inspections
-- RPS and PCIS HFA relay replacement
-- Off-gas system upgrade
-- Snubber inspections and testing
-- Steam separator holddown bolt replacement due of failure to five bolts

During the outage, 132 RHR and recirculation system pipe welds were inspected; with crack indications in 40 welds. Twenty-two of the cracked welds were accepted as-is for use during the test operating cycle, based on a fracture mechanics analysis. Eighteen of the welds were overlay repaired. All ten recirculation safe ends have crack indications in the thermal sleeve to safe end crevice area. Continued operation through the next cycle was justified based on crack growth analysis. Currently, it is planned to replace the ten N-2 nozzle safe ends during the 1987 refueling outage.

The 28-inch diameter "B" recirculation loop inlet (N-1) safe-end weld core sample was taken for metallographic analysis. The results confirmed the absence of cracks in the 316L safe-end material. A weld overlay was installed due to crack indications in the adjacent pipe which is 304 stainless steel. In October 1985, welding of the support brackets for both core spray sparger inlet pipe junction boxes was completed.

On November 2, 1985, the 3C RHR pump motor failed due to a fire in the lower motor guide bearing reservoir. Guide bearing failure was caused by a pump impeller wear ring failure. A new pump and a motor were installed, tested, and placed into service. An investigation concluded that IGSCC of the pump impeller wear ring was the cause of the failure.

On November 16, 1985, the 3A RHR pump was disassembled to replace the pump flange gasket. During disassembly, a cracked impeller wear ring was observed. The 3A RHR motor and pump were repaired and returned to service on November 26, 1985. Because of the problems with the 3A and 3C RHR pumps, the 3B and 3D RHR pumps were also inspected and showed significant impeller wear ring damage. The 3B and 3D RHR pumps were subsequently repaired.

On November 23, 1985, during installation of the steam separator, four of the 48 hold-down bolts broke. Analysis of the bolt concluded that IGSCC was the cause of failure. During removal, one of the bolts was dropped into the annulus region of the vessel, resulting in damage to a jet pump pressure sensing line inside the vessel. The bolt was removed December 8, 1985. TV inspection of the annulus region of the reactor vessel for damage from the dropped bolt found one damaged feedwater sparger nozzle, the lower instrument tap on the number one jet pump broken, and two deformed jet pump instrument lines. Air tests were performed to determine which lines were damaged. The licensee determined that operation during the next cycle without repair of the lines did not present a safety hazard. The licensee also determined that operation was acceptable with the replacement of 24 of the 48 steam separator holddown bolts. Twenty-four new bolts from Limerick Unit 2 were installed in Peach Bottom Unit 3.

The reactor pressure vessel assembly was completed on December 31, 1985. Hydrostatic pressure testing of the reactor vessel began on January 5, 1986. The test was discontinued on January 6, 1986, because of system leaks at 300 psig. After stopping the leaks, the hydrostatic test was started on January 11, 1986, and completed satisfactorily on January 15, 1986. The containment integrated leak rate test was started on January 18, 1986, and completed

satisfactorily on January 23, 1986. The licensee installed a crack monitoring system to simulate crack growth in reactor coolant piping material.

At the end of the assessment period, the licensee was preparing for the loss of power test when the E-2 diesel generator (DG) failed. The resultant DG damage delayed startup testing and Unit 3 return to service.

Common

On September 23, 1985, a PECo chemistry technician drowned while obtaining a sample in the discharge canal. His body was recovered on September 25, 1985, by Pennsylvania State Police divers.

The annual Peach Bottom emergency exercise was held October 17, 1985.

1.3.2 Inspection Activities

Two NRC resident inspectors were assigned to the site during the assessment period. The total NRC inspection hours for the 10 month assessment period was 4153 hours (equivalent to 4983 hours on an annual basis). Distribution of these hours for each functional area is depicted in Table 4.

Special inspections were conducted as follows:

-- Unit 2 Restart Team Inspection, April 10 - 19, 1985
-- HP and Chemistry Team Inspection, July 22 - August 12, 1985
-- Unit 3 Inattentive Operator, June 10 - 14, 1985
-- Unit 3 Restart Team Inspection, October 26 - December 6, 1985.

This report also discusses "Training and Qualification Effectiveness" and "Assurance of Quality" as separate function areas. Although these topics, in themselves, are assessed in the other functional areas through their use as criteria, the two areas provide a synopsis. For example, quality assurance effectiveness has been assessed on a day-to-day basis by resident inspectors and as an integral aspect of specialist inspections. Although quality work is the responsibility of every employee, one of the management tools used to measure Quality Assurance effectiveness is reliance on quality inspections and audits. Other major factors that influence quality, such as involvement of first-line supervision, safety committees, and worker attitudes, are discussed in each area.

Table 2 lists specific enforcement data. Table 3 summarizes all inspection activities during the assessment period

II. CRITERIA

The following criteria were used as applicable in evaluation of each functional area:

1. Management involvement in assuring quality.

2. Approach to resolution of technical issues from a safety standpoint.

3. Responsiveness to NRC initiatives.

4. Enforcement history.

5. Reporting and analysis of Licensee Event Reports, 50.55(e) reports and Part 21 items.

6. Staffing (including management).

7. Training effectiveness and qualification.

To provide consistent evaluation of licensee performance, attributes associated with each criterion and describing the characteristics applicable to Category 1, 2 and 3 performance were applied as described in NRC Manual Chapter 0516, Part II and Table 1.

The SALP Board conclusions are categorized as follows:

Category 1: Reduced NRC attention may be appropriate. Licensee management attention and involvement are aggressive and oriented toward nuclear safety; licensee resources are ample and effectively used such that a high level of performance with respect to operational safety or construction is being achieved.

Category 2: NRC attention should be maintained at normal levels. Licensee management attention and involvement are evident and are concerned with nuclear safety; licensee resources are adequate and are reasonably effective such that satisfactory performance with respect to operational safety or construction is being achieved.

Category 3: Both NRC and licensee attention should be increased. Licensee management attention or involvement is acceptable and considers nuclear safety, but weaknesses are evident; licensee resources appeared strained or not effectively used such that minimally satisfactory performance with respect to operational safety or construction is being achieved.

The SALP Board has also categorized the performance trend over the last quarter of the SALP assessment period. The categorization describes the general or prevailing tendency (the performance gradient) during the last quarter (November 1985 - January 1986) of the SALP period. The performance trends are defined as follows:

Improving: Licensee performance has improved during the last calendar quarter of the assessment period.

Consistent: Licensee performance has remained essentially constant during the last calendar quarter of the assessment period.

Declining: Licensee performance has generally declined over the last calendar quarter of the assessment period.

III. SUMMARY OF RESULTS

3.1 Overall Facility Evaluation

During this assessment period performance problems continued to manifest themselves at Peach Bottom. Management involvement and effectiveness toward improving operating activities have not been evident. Indications of the lack of adequate management involvement and effectiveness include: poor dissemination of management goals and policies; poor communication between the different departments and divisions; and a focus on compliance concerns rather than acknowledgement and correction of the root causes of problems.

An area of continued major concern is the number of reactor shutdowns and protection system challenges which have occurred. As noted in Table 5 a large number of these are attributed to personnel errors. A common cause of the personnel errors appears to be inattention to detail resulting from failure to either follow or consult the appropriate procedure, indicating a complacent attitude toward procedural compliance. The complacent attitude is also exhibited in poor work practices that generate unnecessary protective system challenges. While initiatives to address scram causes have been in place, permanent corrective actions are considered ineffective, and higher levels of management involvement are necessary to redirect this effort.

Routine activities do not seem to receive appropriate management attention. The number of underlying issues (e.g., inattention to detail, poor followup on commitments, poor oversight of contractors and a lack of aggressiveness in identification and resolution of routine problems) and the defensive attitude of management, leads us to conclude that there is a problem with how corporate policies are understood and adhered to on-site. This problem has resulted in a detached attitude at the site; although a number of functional areas are rated as Category 2, the historic lack of improvement is of concern. In particular, the Security Area epitomizes a lack of aggressive management in assuring that the licensee's policies, practices and procedures, were understood by contractor personnel. Further, it is not clear that those who have responsibility are being held accountable. Recent events associated with control rod withdrawal errors during a startup, although outside the assessment period, are another indication of management not effectively assuring that the responsibility and accountability for proper operations are sufficiently understood, resulting in many instances of sloppy work practices and a sense of complacency.

In contrast to the above, major evolutions at Peach Bottom associated with primary system piping replacement and major hardware modifications did not reflect the shortcomings noted in the previous paragraphs. This has resulted in a favorable Category 1 rating for Refueling/Outage Activities. The good performance in this one functional area can be attributed to the fact that the work was planned, directed and executed in close coordination with the engineering department. Engineering support historically has been noteworthy in construction oriented activities.

3.2 Facility Performance

	Functional Area	Category Last Period (January 1, 1984 to March 31, 1985)	Category This Period (April 1, 1985 to January 31, 1986)	Trend
1.	Plant Operations	2	2	Declining
2.	Radiological Controls	3	2	Consistent
3.	Maintenance	1	2	Consistent
4.	Surveillance	2	2	Declining
5.	Fire Protection & Housekeeping	2	2	Consistent
6.	Emergency Preparedness	2	2	Consistent
7.	Security and Safeguards	3	3	Improving
8.	Refueling/Outage Activities	1	1	Consistent
9.	Training and Qualification Effectiveness	Not Evaluated	2	Consistent
10.	Assurance of Quality	Not Evaluated	3	Consistent
11.	Licensing Activities	1	2	Consistent

IV. FUNCTIONAL AREA ASSESSMENTS

4.1 Plant Operations (31%, 1300 hours)

Analysis

During this assessment period, resident and specialist inspections routinely reviewed plant operations. The functional area of plant operations was also reviewed during team inspections prior to each unit restart following the refueling outage periods. These two restart team inspections concluded that each unit could be safely returned to reactor power operations.

During the assessment period, a total of thirty-five automatic scram signals and unplanned shutdowns occurred as follows: Nineteen automatic scrams on Unit 2 (eight at power with rod motion); three unplanned shutdowns on Unit 2; and, thirteen automatic scrams on Unit 3 (shutdown reactor protection system challenges). These scrams and shutdowns are listed in Table 5, including descriptions and causal analyses as determined by the SALP Board.

Eight scrams can be attributed to personnel errors by operations personnel. Six scrams can be attributed to errors by licensed operators, and two scrams due to errors by non-licensed operators. A common cause of these personnel errors appears to be operator inattention to detail resulting from failure to either follow or consult the appropriate procedure There appears to be a complacent attitude among operators with respect to procedural implementation and compliance. One additional scram can be attributed to poor control of work activities, in that a procedure did not provide an appropriate caution.

There were several other instances where lapses occurred in procedural adherence. For example, the following procedural violations occurred: Unit 2 control rod blocking (tagout) while full out, improper control room supervisor shift relief, improper preparation of equipment blocking permits on Unit 3 and vessel draining on Unit 2 during RHR shutdown cooling operation. The control rod blocking while full out during reactor power operation was particularly disturbing because two licensed and one senior licensed operators were cognizant of the situation. When the inspector noted that the control rod was full out and blocked, so that it would not insert during a scram, the licensee initiated immediate action to return the rod to an operable condition. Less than one hour after the control rod drive was returned to service, a reactor scram occurred. Licensee corrective actions included a revision to the control rod blocking sequence specifically requiring the rod to be full in prior to its removal from service.

The return to power operations for Unit 2 following the 15 month pipe replacement and refueling outage commenced in July 1985. Unit 2 startup testing, after an extended outage in which recirculation piping was replaced and the plant was refueled, was well controlled and adequately managed. Testing included modification

acceptance tests, refueling acceptance tests, and routine surveillance tests. Plant management was heavily involved in testing, problem resolution and testing decisions including frequent meetings. A PECo manager was assigned to coordinate the overall test program as his only responsibility. Testing was performed in a cautious manner. All increases in plant power during Unit 2 restart were accomplished with the forethought of reactor safety and safety of plant equipment. There was an ongoing audit by QA personnel of plant testing progress. Daily and shift status meetings were conducted to discuss test scheduling, to review problem areas, and to pre-brief personnel on test procedures. Restart team staffing appeared to be good. Sufficient personnel were available to conduct testing at remote locations.

Management decisions regarding plant and reactor safety are usually conservative as evidenced by power reductions and shutdowns that were not required by Technical Specifications. One case of non-conservative operation was the decision by plant management to swap reactor feed pumps (RFP) at 44% power. The RFP swapping evolution resulted in a water hammer transient and reactor scram during troubleshooting activities although no procedure to control this evolution existed.

Control room operator response to plant transients and reactor scrams continues to be a strength as evidenced by inspector observations during several transients. Operators effectively use the symptom-oriented emergency operating procedures and associated checklists called Transient Response Implementation Plan (TRIP) procedures.

The assignment of an additional senior licensed operator, stationed outside the control room, relieves the shift superintendent of certain administrative duties ("Outside" Shift Supervisor) on the day and afternoon shifts Monday through Friday and is a strength. The licensee is planning to increase the manning of the "Outside" Shift Supervisor position to full time (i.e., 21 shifts per week).

With respect to control room activities, there is no evidence of control room distractions and interior noise level is controlled. However, at times the public address system tends to distract from control room formality. The addition of a control room carpet has aided in noise control. Access to the general control room area is restricted by the vital area doors. The Unit 2 door has recently been restricted to operations personnel only. The overall control room appearance and cleanliness is good with no evidence of inappropriate material.

Licensed shift operators are generally alert and attentive to control room panels and indications. However, an apparent inattentive Unit 3 licensed operator was not recognized and dealt with by shift supervision until noted by an NRC inspector in June 1985.

It appears that the on-site review committe (PORC) should be more self-critical in an attempt to anticipate problems, especially in regards to the number of recurring personnel errors. Although plant procedures did not require PORC review and approval of modification test results, PORC chose to review the completed Modification Acceptance Tests as well as the test procedures for Unit 2. The PORC is functioning well for routine activities based upon observation by inspectors at several PORC meetings during the assessment period. However, two instances in which PORC review was not thorough in more complex cases were the safety evaluations for the radwaste storage facility (see section 4.2) and, the safety evaluation for the Unit 3 steam separator bolt and jet pump instrument damage. The initial safety evaluation of the jet pump instrument line damage did not include evaluation of potential damage from reactor operation, loose parts considerations, adequate information on using three instead of four calibrated jet pumps to allow core flow assessments during operation. The safety evaluation has been revised to include the above concerns.

The licensee has had difficulty adhering to NRC reporting requirements. In August 1985, with Unit 3 shut down and defueled, the licensee instituted a policy of not reporting RPS actuations, which was promulgated by a memorandum in conflict with an approved procedure. Based on the licensee's interpretation of the 10 CFR 50.72 and 50.73, and NUREG 1022 reporting requirements, NRC notification was not made for eight RPS actuations that occurred between August 29, 1985 and October 10, 1985. Following discussions with NRC Region I, the licensee withdrew the policy of not reporting RPS actuations.

The licensed operator training program resulted in one operator and three senior operators being licensed during this assessment period. In addition, two candidates passed the senior operators examination as part of instructor certification. No significant areas of weakness were noted during the written examinations. However, a weakness was noted in the use of procedures during the simulator portion of the exam. Specifically, the candidates had difficulty in locating and differentiating between the applicable procedures during the simulator scenarios. Overall, the licensee's replacement operator training program is adequately implemented as evidenced by performance on NRC administered examinations.

A review of the licensed operator requalification training indicates a properly functioning program, with two strengths and one weakness noted. The one noted strength was that lesson plans prepared by the Training Section for licensed operator requalification were well written, and presented by highly qualified instructors. The second strength was the oral walkthrough examination guide prepared for the requalification examination, which was of high quality. The noted weakness was that the licensee's requalification program does not ensure that those staff member(s) reviewing the annual written requalification exam are periodically administered an exam themselves. One staff member had not taken a written exam for four years. The licensee responded to this weakness by rotating the review of the exam through four senior staff members. Thus each senior staff member would periodically take the requalification exam.

Housekeeping throughout plant and station areas was determined to be adequate during the assessment period, with improvements noted from the prior assessment period. Routine inspections of the Unit 2 and Unit 3 drywells during the outage period revealed adequate cleanliness. Site QC has responsibility for evaluating housekeeping and they appeared to be effective in early identification and resolution of housekeeping discrepancies. Housekeeping conditions, noted problem areas and corrective actions were routinely discussed at the daily and weekly outage meetings.

Management controls to assure that approved procedures were not revised informally were weak in that two cases were noted where problems arose. Faulty guidance modifying administrative procedure requirements resulted in a number of RPS actuations not being reported in a timely manner. The licensee had written a memorandum allowing non-licensed operators to prepare blocking permits, which was contrary to administrative procedures. When notified of this discrepancy, the licensee revised the administrative procedure in an apparent non-conservative direction, to allow the non-licensed operators to prepare the blocking permits. Licensee response to these issues is under review by the NRC.

In summary, operations is staffed with an adequate number of licensed and non-licensed operators, and management personnel. Appropriate procedures and hardware are in place. However, during the recent history of extensive outage activities a complacent attitude towards procedural adherence and support of plant operations has become evident. Management actions to address these issues in the past have not been effective.

Conclusion

Rating: Category 2

Trend: Declining

Board Recommendations

Licensee:

-- Address the apparent complacent attitude and stress procedural compliance.

-- Address the number of and repetitiveness of reactor scrams and personnel errors.

NRC:

-- Conduct a team inspection to better understand underlying reasons for licensee's historial performance problems.

4.2 Radiological Controls (12%, 495 hours)

Analysis

Inspection efforts in this area included six inspections by Region Specialists in the program areas detailed below; and, two inspections conducted by Agreement State representatives and reviewed by NRC Region I. Day-to-day review of ongoing activities was provided by the Resident Inspectors.

During the previous assessment period, programmatic weaknesses in the radiation protection and transportation areas resulted in the radiological controls area being assessed as Category 3. During the current assessment period, significant problems were noted in the transportation area. However, improvements were noted in radiation protection. The overall area of radiological controls has improved.

Radiation Protection

Four inspections, including a special team inspection during the Unit 3 refueling outage, indicated that management attention was directed to improving performance in radiation protection. A plant reorganization separated the radiation protection and chemistry functions, and established a separate ALARA section within the radiation protection organization. Key positions, (e.g., the Health Physicist-ALARA), within the reorganized radiation protection group were filled in a reasonable time. However, authorities and responsibilities for the Health Physicist-ALARA, altered duties of the Health Physicist Support and the new reporting relationship for the Senior Health Physicist were not reflected in the licensee's position guides and procedures.

The inability to take effective corrective action to prevent recurrence of radiation protection problems was brought to the licensee's attention during the previous assessment period. Improvements in radiological controls for outage work activities were noted during this assessment period indicating that the licensee had directed attention to improving management review and control of radiation protection activities. Improvements in management review of outage work activities noted included: The assignment of lead radiation protection personnel, an improved communication of work scope and job location, an increased surveillance of work areas, a better review of work packages, a better defined outage responsibility for the newly-formed ALARA section, and weekly reviews of outage problem areas by senior radiation protection management.

Corrective actions appeared to be effective as evidenced by the review of the Unit 3 core spray sparger "T" box repair activities. The licensee conducted an adequate and generally effective planning and preparation phase including review of previous repair work, construction of a mock-up to train personnel, and use of a shielded work station to control exposures. External exposure controls were well-organized and included continuous dose assessment and control, adequate surveillance of potentially changing dose rates, and continuous access control to the work area. A generally adequate program to control contamination and prevent internal exposures to workers including auxiliary ventilation, close supervision of respiratory protection practices, and strict radiation work permit controls was noted. A generally improving ALARA program including dose tracking, administrative exposure control, and recording of exposures and dose rates for possible use during future work on Unit 2 was provided.

An ineffective training program for the radiation protection staff was noted during the previous assessment period. Training program improvements were noted in the training of contractor and senior licensee radiation protection technicians suggesting increased management attention. General employee training (GET) and general respiratory training (GRT) programs were satisfactory except for uncertain policies regarding pregnant female contractor employees. In addition, professional staff training in radiation protection was lacking. Although the licensee had planned a 60 topic program of professional training to be completed over a three year period, (i.e., 1982-85), approximately one-half of the program had not been completed by July 1985. When brought to the licensee's attention, the licensee indicated that efforts were underway to provide additional training.

The review of the licensee's quality assurance program, as it related to the radiation protection program, indicated that management attention had been directed to improving and strengthening the licensee's capability to identify and correct radiation protection deficiencies. Radiation protection professional personnel reviewed ongoing work activities to ensure that radiation work permit and control point radiological controls were being observed. Quality control personnel inspected ongoing work activities to ensure that radiation work permit and control point radiological controls were being observed. Quality control personnel inspected ongoing work activities using detailed monitoring checklists containing appropriate radiation protection attributes. Audits of radiation protection operations and the ALARA program were conducted by qualified quality assurance personnel.

Radioactive Waste Management and Effluent Monitoring

Two inspections by Radiation Specialists reviewed the design, construction, testing and proposed operation of the low-level radioactive waste storage facility and effluent monitoring activities. The Resident Inspectors reviewed day-to-day operations of the licensee's radioactive waste management and effluent monitoring program. No effluent release limits were exceeded.

The licensee's safety evaluation report and PORC review for the low-level on-site radioactive waste storage facility did not consider the potential radiological consequences of a fire in the facility's storage cells suggesting a lack of thorough technical review in the licensee's 10 CFR 50.59 review process. Review of the preoperational testing of the facility had not been completed although the testing had been completed indicating a lack of timely technical review.

Transportation

Three inspections, including a special inspection and two inspections by Agreement State representatives reviewed by NRC Region I, identified five problems and several weaknesses in the transportation area. Burial privileges at two Agreement State waste disposal sites were temporarily suspended during the assessment period. An Enforcement Conference was held with the licensee on November 14, 1985, to discuss the problems and weaknesses noted.

Multiple problems were noted in the transportation area. Repetitive problems with lifting cables used to remove palletized high integrity containers from shipping casks resulted in a civil penalty assessment and suspension of burial site privileges by South Carolina. Failure to provide a strong-tight container for a low specific activity container resulted in suspension of burial site privileges by Washington. Corrective action was timely and included studies to determine the causes of the problems and additional training for radioactive waste operators.

Poorly stated procedures for shipments of irradiated control rod blades suggesting inattention to technical detail in the review of special shipping procedures were noted. Procedures failed to ensure that each cask liner loaded into the Model FSV-1 shipping cask (Certificate of Compliance No. 6346) corresponded to the liner and contents described in the shipping papers. Procedures for draining residual fuel pool water from irradiated control rod blade shipments resulted in contamination of the external trunion cup area of the FSV-1 cask. Timely corrective actions taken by the licensee included a quality control verification of the liner/shipping paper correspondence and a provision for access to the trunion cup area for decontamination and contamination surveys.

Events, including the problems with control rod blade and routine radioactive waste shipments, were reported in a timely manner although information relating to the causes and potential corrective actions was incomplete when reported. The licensee promptly dispatched professional representatives to the burial sites to assess and review the problems and recommend corrective actions. At the Enforcement Conference on November 14, 1985, the licensee addressed each problem noted with immediate corrective actions and long term follow-up plans.

A generally effective surveillance and inspection program was implemented by the site quality control organization including detailed monitoring checklists and mandatory inspection hold points in procedures related to shipping.

Review of the licensee's quality assurance program in July 1985, as it related to transportation activities, indicated that the licensee had implemented an audit program for shipping activities addressing applicable criteria in 10 CFR 50, Appendix B. Corrective action measures initiated as a result of audit findings were reviewed for implementation during follow-up audits. Adequate quality assurance procedures and checklists have been used in auditing shipping activities. The licensee reviewed the quality assurance program to ensure that adequate procedures were in place to implement the quality assurance plan for transport packages.

Conclusion

Rating: Category 2

Trend: Consistent

Board Recommendations

Licensee:

-- Complete long-term transporation related corrective actions discussed during the November 14, 1985 Enforcement Conference.

-- Evaluate the effectiveness of the QA program relative to transportation related problems.

NRC:

-- Conduct augmented inspection of transportation area and QA activities to review licensee's long-term corrective actions.

4.3 Maintenance (9%, 367 hours)

Analysis

The maintenance area was assessed as Category 1 for the previous SALP period. That assessment observed that management was strongly involved in maintenance activities, personnel were well trained, work adequately planned, procedures were found to be detailed, and maintenance workers were observed to follow procedures.

During this assessment period maintenance activities were reviewed during each resident inspection. Specialist inspections examined maintenance and related activities during reviews of plant modifications, responses to IE Bulletins, reviews of corrective and preventive maintenance programs, and maintenance associated with outages on both units. Specific maintenance activities reviewed included; snubber testing and rebuilding, emergency service water (ESW) system cleaning and ESW pipe replacement, control rod drive exchange, diesel generator maintenance, RHR pump and valve inspections and repairs, core spray sparger work, and plant modification. During this assessment period the licensee has been generally responsive to NRC concerns regarding maintenance activities.

Poor work practices by maintenance personnel resulted in 13 unplanned reactor scram signals while shutdown. The cause of these scrams was due to bumping reactor scram sensors and cables under the reactor vessel. Also, two unplanned reactor shutdowns were caused by inadequate spare parts for safety related valves.

Extensive management involvement in the larger maintenance activities has resulted in a beneficial influence on both the control and the quality of maintenance and modifications. Large maintenance tasks appear to be well planned and executed, as demonstrated by both the recent control rod drive (CRD) changeout and the core spray sparger "T" box repair on Unit 3. The licensee provided adequate mock up training and had detailed procedures for both tasks. Few problems were encountered with the CRD changeout and the work proceeded on schedule. The MOD associated with the repair of the crack in the core spray sparger was examined in detail. The work inside the reactor vessel was well planned and conducted in an efficient manner with minimum personnel radiation exposures.

Smaller maintenance tasks appear to suffer in many cases from lack of planning and management attention. It appears that the smaller jobs may result in a lower quality of work. The problems associated with the three failures of Unit 2 RHR 154A motor operated valve could have been reduced with more accurate and specific maintenance procedures, better vendor information, and a more thorough determination of failure root causes. Maintenance Division workers apparently installed the valve operator yokenut and locknut spare parts on the valve stem without consideration of proper thread engagement. The

poor thread engagement fit caused two additional failures, requiring a shutdown of Unit 2 each time. Maintenance Division engineering was not contacted until the second valve failure. It appeared to take two Unit 2 shutdowns to get appropriate management attention to the valve repair activities.

Several inspections reviewed the corrective and preventive maintenance programs. The programs were found to be adequately established and activities were being monitored via the Computerized History and Maintenance Planning System (CHAMPS). A portion of the equipment qualification program was also being incorporated into the CHAMPS. The computer program gives the licensee a better capability for researching equipment history and trending equipment failures. A post maintenance testing program, as required by Generic Letter 83-28, was found to be in place and was being implemented satisfactorily.

As a result of problems identified in the use of liquid nitrogen for containment inerting at another BWR in early 1984, an inspection followup was conducted regarding licensee actions in response to five recommendations made by General Electric. Four of the five recommendations had been carried out by the licensee. However, the evaluation of inerting system operation involved a commitment to functionally test such operational features as the liquid nitrogen vaporizer, a low temperature shutoff valve and a low temperature switch. The modifications to perform this testing, the test procedure and the test had not been accomplished in a timely manner. There has been slow response and considerable delay in the implementation of commitments made in March 1984.

A large number of Unit 3 safety related snubbers failed the functional tests performed. Questions were raised regarding test acceptance criteria, the cc sequences and causes of the large number of failures, and proper maintenance practices. Similar problems were noted on Unit 2 snubbers during the December 1985 outage. The program for assessing operability of snubbers needs continued licensee management review.

During this assessment period, a number of problems occurred with the RHR pumps which required a large maintenance commitment. Problems included a fire in the 3C RHR pump motor, wear ring cracking on several RHR pumps and low flow conditions with the 2A RHR pump. The related maintenance activities appeared to be well planned with adequate management attention. The licensee's investigation of root causes and subsequent reporting of the RHR pump wear ring problems appeared to be thorough.

Several inspections focused on diesel generator (DG) maintenance activities, including the removal of the interpolar connecting bars, the replacement of the scavenging air blower, and the DG annual preventive maintenance. Maintenance workers were found to be knowledgeable, well trained, and performed the work in a timely manner. However, there appears to be a lack of communication between Maintenance Division workers and Maintenance Division engineering. It appears that Maintenance Division foremen were the only ones knowledgeable of two service information letters (SILs) issued by Fairbanks-Morse in November 1984 and October 1985 concerning the potential for scavenging air blower failure when running the DG at low loads. Apparently, maintenance engineering, mechanical engineering and operations personnel did not become aware of the SILs until after the DG scavenging air blower failure. Wider knowledge of the SILs could have prevented running the DG for 51 hours at low loads.

Formal controls over vendor manuals have been established and vendor evaluation of the state of the manuals was obtained. However, neither site maintenance procedures nor the Walworth vendor manual for the RHR 154A motor operated valve were specific enough to include the actual stem engagement design.

The licensee uses operating experience feedback in its maintenance program. For example, based on problems with Unit 3, the ESW piping was cleaned and some pipe sections replaced. The work proceeded noticeably smoother on Unit 3 than earlier work on Unit 2. Other examples include expanded maintenance activities on the RHR pumps and snubbers.

A review of maintenance considerations to safeguard against overpressurizing low pressure ECCS piping indicated that activities were well planned and conducted. The maintenance history on the interface valves is stored on a computer and is readily retrievable for engineering studies. The design of piping systems and testing logic provides protection against overpressurization of the low pressure piping. The interface valve leak tighness is assured through implementation of the preventive maintenance program.

Conclusion

Rating: Category 2

Trend: Consistent

Board Recommendations

Licensee:

-- Improve the control of vendor information.

NRC: None

4.4 Surveillance (12%, 483 hours)

Analysis

In the current assessment period, region-based inspectors conducted inspections of the containment integrated leak rate test (CILRT) and the local leak rate test (LLRT) programs. Inspections also reviewed surveillances applicable to health physics, fire protection, refueling equipment, maintenance activities, snubbers, emergency preparedness, and environmental monitoring. A programmatic review of the surveillance program was conducted during the Unit 2 restart team inspection. Resident inspectors routinely reviewed selected surveillance program areas each month.

The previous assessment period noted the following problems regarding surveillance test activities: surveillance tests not completed after the tests had begun, specific steps required by Technical Specifications not denoted as such, inadequate review of surveillance results by technical personnel and failure to follow a surveillance test procedure. These problems were not evident during this assessment period.

Management involvement in prioritizing personnel assignments to assist in the surveillance test program was good. Management was also involved in surveillance test preparation and solving problems that arose. The licensee took conservative positions on surveillance testing when questionable areas were identified, and was generally responsive in providing requested information.

There were six automatic scrams during this assessment period related to surveillance testing. Four of these scrams were attributed to personnel error and two resulted from random equipment failures. The scrams were all on Unit 2. During Unit 2 pre-startup testing, technicians used a new instrument line backfilling device which caused excessive water pressure to the instrument lines and resulted in scram signals while shut down. Use of this new backfilling device was suspended. Attention to detail and proper planning could have eliminated most of these events.

Two surveillance tests were missed during the assessment period. One of the tests was an I&C surveillance on a portal monitor and the other was a Unit 3 safety relief valve (SRV) manual actuation test. The missed I&C surveillance was due to an oversight by the I&C group. The SRV test was only partially completed (8 of 11 SRVs tested) and resulted in 3 SRVs not being tested during the Unit 3 cycle from September 1983 to July 1985.

Plant chemistry was reviewed during routine resident inspections and during two specialist inspections. A reorgnization of the chemistry group is considered to be a licensee strength based on the following: (1) a full time Senior Chemist heads the group, (2) the chemistry group reports directly to the Superintendent, Operations, and, (3) the reorganization improves ties with plant operations. A review of the chemical analytical program determined that the licensee has the capability to make consistently accurate radioactivity and chemical measurements. A goal of 0.3 micromhos/cm has been set for reactor water conductivity. The goal is well below the Technical Specification limit of 5.0. When the goal is not achieved, plant power reductions or shutdowns have been effected to repair condenser leakage. Thus, an overall conservatism has been shown by the licensee with respect to operational chemistry.

The Unit 2 and Unit 3 CILRT were satisfactorily conducted during the assessment period. The contractor was effective in assisting the licensee during test performance. A problem regarding the LLRT test direction for stem leakage with valve AO-2502B during the Unit 2 test was handled properly. However, the licensee did not immediately take the initiative to see if other valves had the same potential for untested stem leakage.

The "as-found" Unit 2 LLRT data required some engineering judgement to support leakage values. Even though conservative values were used, the licensee recognized that engineering judgement was a weak justification for the as found leakage value. The licensee recognized that in a few cases a LLRT was not performed prior to maintenance. The licensee subsequently ensured LLRTs were performed prior to maintenance and improved LLRT performance on Unit 3. The CILRT personnel have now been given responsibility for the LLRT program, and an improvement in test control has been noted.

During a review of the surveillance program near the end of the assessment period, a major weakness was noted. Neither the Peach Bottom Technical Specifications nor administrative procedures address requirements or contain guidance regarding actions to be taken relative to overdue surveillance tests. Management controls for the surveillance testing program are not adequate to ensure system operability when called upon to function in that the current program does not address actions to be taken when the equipment surveillance testing interval has been exceeded. This is indicative of a lack of management sensitivity to assuring system operability.

In summary, improvements are noted in leak rate testing conduct, however management philosophy toward the conduct of the surveillance program is weak.

Conclusion

Rating: Category 2

Trend: Declining

Board Recommendations

Licensee:

-- Establish management policy and controls which reflect the relationship between surveillance testing and equipment and system operability

NRC: None

4.5 Fire Protection (4%, 173 hours)

Analysis

In the current assessment period, fire protection was reviewed during two specialist inspections and as part of each resident inspection. A routine specialist inspection was conducted for fire protection modifications required by 10 CFR 50, Appendix R Sections III.G.3 and III.L. A reactive specialist inspection investigated the cause and corrective actions associated with a cable tray fire in the Radwaste Building.

During the previous assessment period, the licensee continued to make improvements in fire protection. Maintenance of fire barriers, access to fire equipment, outage related housekeeping activities and onsite fires were identified as areas requiring improvement and increased management attention.

The licensee developed detailed modification packages for the design changes, construction, and post-modification testing for plant modifications for Alternate Shutdown Capability (10 CFR 50, Appendix R, Sections III.G.3 and III.L). The modification packages were reviewed for technical adequacy and compliance with the NRC requirements and the licensee commitments in this area. The licensee's administrative procedures were verified to be adequate for the control of the modification activities. Licensee personnel involved in the various stages of the modification are well qualified and trained. Human factor considerations were employed in arranging the devices and switches on the alternate shutdown panels, maintaining similarity to the control room configuration.

Two major fires occurred during the assessment period. The first fire occurred on November 2, 1985, in the 3C RHR pump motor (Unit 3). The fire was detected by installed fire detectors. The second fire occurred on November 10, 1985, in a non-safety related cable tray and divers' equipment cage in the Radwaste Building (common to Units 2 and 3). This fire was detected by a roving fire watch, and subsequently by alarming fire detectors. Licensee fire brigade response in locating both fires and subsequent fire suppression with portable equipment was good. The cause of the 3C RHR pump motor fire was equipment failure resulting in the motor oil reservoir and the motor windings igniting. The cause of Radwaste Building cable tray fire remains unknown.

With respect to the Radwaste Building fire, a lack of conservatism was evidenced by the licensee's interpretation of the fire protection requirements. If a degraded fire barrier exists, TS require that a continuous fire watch be posted or a roving watch be established, if the detectors on one side of the affected barrier are operable. The fire hazard analysis had determined that a fire barrier is required for the Fan Room of the Radwaste Building to comply with Appendix R,

Section III, and additional detectors are required in the Fan Room. Since the existing detection system was operable, the licensee established a roving fire watch. Although the licensee met the TS, a conservative interpretation would have provided for a continuous fire watch since the same study that identified the need for a fire barrier also identified the need for additional fire detection. After the fire, a continuous fire watch was established.

Conclusion

Rating: Category 2

Trend: Consistent

Board Recommendations

Licensee:

-- Assess the results and evaluations of the radwaste building cable tray fire.

NRC:

-- Meet with licensee to discuss the assessment of radwaste building fire.

4.6 Emergency Preparedness (10%, 431 hours)

Analysis

During the assessment period, emergency preparedness activities included a programmatic inspection in June 1985 and observation of the annual emergency preparedness exercise in October 1985 by a team of twelve NRC and NRC contractor personnel. The Resident Inspectors monitored licensee performance throughout the period.

During the previous assessment period, problem areas were identified in the training of personnel in the emergency preparedness organization, in licensee audits, and in failure to provide accurate emergency initiating conditions. These are were re-evaluated during this assessment period. Although progre was made in all of the deficient areas, the licensee was slow to respond.

During the annual emergency exercise significant deficient areas were noted. These deficiencies were partly due to lack of training for emergency personnel (which was delayed due to the Uni 2 piping replacement outage) and resulted in a confirmatory action letter (CAL) issued on November 5, 1985. The CAL addressed four areas that required improvement including:

1) Clear delineation of the current emergency organization with authority and responsibilities well documented in the Emergency Plan;

2) Definitive protective action decision-making procedures with the basis and methodology for implementation;

3) Precise emergency action levels based upon the integration of plant parameters, and radiological and environmental conditions, and;

4) Comprehensive training program for key emergency response personnel including both classroom and practical training.

The licensee's corrective actions for the first three areas have been completed. Training for key personnel is ongoing with the classroom and practical portion scheduled to be completed by March 31, 1986. In addition, three drills have been scheduled in 1986, prior to the next annual emergency exercise. NRC review of the above actions is pending.

Corporate support is more evident in the emergency planning program and a new corporate incident response facility has been completed and successfully tested as part of the last exercise. Current on-site staffing in the emergency preparedness area consists of one full-time on-site experienced planner, corporate staff support and two contractor trainers. An improvement in emergency planning staffing has been noted during the last few assessment periods.

The licensee's QA organization has not been used effectively to audit the overall implementation of the emergency preparedness program. Previously identified problem areas do not appear to be tracked and resolved. The audit program was found to lack followup on previously identified deficiencies in the emergency preparedness area.

In summary, the licensee has provided additional resources to resolve the identified problem areas. However, progress throughout the period, although steady, has been slow.

Conclusion

Rating: Category 2

Trend: Consistent

Board Recommendations

Licensee:

-- Improve QA audit resolution and corrective action followup activities of emergency planning.

-- Promptly complete the actions required of the CAL.

NRC: None

4.7 Security and Safeguards (6%, 238 hours)

Analysis

Three unannounced physical protection inspections were performed during the assessment period by region-based inspectors. One material control and accounting inspection was conducted. Routine resident inspections continued throughout the assessment period.

Two security event reports were submitted pursuant to the requirements of 10 CFR 73.71. One report pertained to a computer failure and the other related to a failure in the AC power system. Each event was adequately handled and appropriate compensatory security measures were implemented.

Security program implementation during periods of routine plant operations was satisfactory. However, during April 1985, with Unit 2 at the end of a major outage, a routine physical security inspection identified several problems (access control and alarm response) and an Enforcement Conference resulted. Similar problems were identified during June 1984, when Unit 2 was beginning the major outage. NRC identified problem areas were addressed by the licensee during a May 1985 Enforcement Conference and actions to prevent recurrence for the issues were provided at that time. The security problems stemmed from the licensee's less than adequate supervision and oversight of the security contractor.

In reviewing the security deficiencies that were observed during the April 1985 Unit 2 outage, of particular concern was the fact that members of the security force again did not respond to alarms in vital areas. The failure to respond to alarms was further compounded by a breakdown in communication between the licensee and the security contractor, in that there was confusion regarding the implementation of oral instructions. Security force members failed to recognize degraded security situations similar to the June 1984 events. Additionally, neither the contract security supervisors nor licensee management were exercising sufficient oversight of the guard force; and, they were either unaware of or did not recognize certain events as serious security system breakdowns.

Although senior licensee management made a previous commitment to NRC to provide more effective oversight of the security contractor, there was still a serious lack of pre-planning by the security staff for major maintenance outages. The problems which occurred during the last assessment period and those during this period appear to share the same general root cause: inadequate licensee management attention to and control of the security contractor. In addition, the failure of the security staff to adequately plan and prepare for outage periods is evident. The security force contractor did not fully analyze the additional outage security

needs or take positive and effective action to meet the objectives of commitments outlined in the NRC-approved physical security plan. Additional management attention to this matter was required.

During the assessment period, the licensee transmitted revisions to the Security Plan under the provisions of 10 CFR 50.54(p). These revisions were in response to NRC letters advising that portions of a previous plan change were not considered acceptable and required modification or a change to the previously approved plan. The revisions were submitted by the licensee as requested and these were considered acceptable. In general, the plan changes were found to be of good quality and indicate a thorough knowledge of security objectives. The licensee's corporate security staff is responsible for ensuring that security plans are maintained current and for coordinating changes when required. The licensee has been effective in this area and have been responsive to Region I concerns and comments regarding security plan changes. They also communicate with Region I staff when more complex changes are required.

During the latter portion of this assessment period, some improvement in the overall performance of the licensee's security management staff and that of the security force contractor was apparent. The licensee has hired a Nuclear Security Specialist to assist the Administrative Engineer and Plant Manager in responding to the needs of the security program. The findings of a recent security specialist inspection demonstrated the effectiveness of this action as evidenced by more timely and comprehensive response to previous inspection findings. The security force contractor has proposed an enhanced training and qualification program for its personnel which exceeds the existing training standards and is designed to respond better to the current and future security needs of the licensee. The proposal is currently under evaluation by the licensee. These actions demonstrated that increased management attention was being directed to security program implementation.

Conclusion

Rating: Category 3

Trend: Improving

Board Recommendations

Licensee:

-- Provide closer day-to-day management oversight to assess the control of the contractor security force.

-- Establish measures to anticipate demands for needed resources of the security organization.

NRC: None

4.8 Refueling/Outage Activities (16%, 666 hours)

Analysis

The previous assessment of refueling/outage activities focused on Unit 2 because it was shut down for most of the period to replace recirculation system and RHR system piping. The licensee's performance was Category 1 during the last evaluation period.

During this assessment period both units experienced outages. Unit 2 was in the pipe replacement outage from the beginning of the period until July 6, 1985, when the unit was restarted. On November 29, 1985, Unit 2 went into a mini-outage for equipment qualification (EQ) modifications and other work until returning to service on December 25, 1985. Unit 3 was shut down on July 14, 1985, for its sixth refueling outage and remained in an outage through the end of January 1986. Unit 3 experienced problems during the outage, such as damaged jet pump instrument lines, broken shroud head hold down bolts, extensive weld overlay work and NDE, all-inclusive snubber inspections and repair, RHR pump inspections and repair, DG scavenging air blower failure, and core spray sparger repair.

Team inspections were performed to assess the readiness of each unit prior to restart. Various regional inspectors examined outage/refueling activities and the resident inspectors reviewed licensee activities in this area during each inspection. Aspects of outage activities assessed during this period included QA and QC coverage, modification control and acceptance testing, welding, purchasing, inservice inspection (ISI), nondestructive examination (NDE), control of contractors, management involvement, procedures, planning, audits, fuel reconstitution, core reload, and response to generic issues.

Licensee engineering took an active role in the resolution of problems related to intergranular stress corrosion cracking (IGSCC) indications found in the Unit 3 recirculation and RHR system piping, core spray spargers, and the recirculation inlet and outlet nozzles. Contractor engineering and construction services were used effectively and NRC was informed of work status and problems in a timely manner. Where weld overlay or welding was used to provide structural strength, welder qualification, performance of welding, documentation and QC involvement were determined to meet ASME code standards and regulatory requirements.

Review of ISI activities of Unit 3 was directed toward work in meeting the requirements of NRC Generic Letter 84-11 for detection of IGSCC. The licensee's ISI program was staffed with an adequate number of competent, knowledgeable personnel. Planning and careful completion of tasks in ISI was evident. Contractor services were used for NDE of stainless steel recirculation and RHR piping welds,

for overlays on Unit 3 welds, and the set up of equipment to detect and establish growth rates of IGSCC. An in-depth review of these activities concluded that licensee and contractor personnel provided excellent coverage of NDE work. The licensee provided for daily involvement of ISI coordinators and the authorized nuclear inservice inspector and for overall supervision of NDE activities in addition to the normal ISI program.

Both resident and regional based inspectors reviewed the fuel reconstitution activities. The expertise of contractor personnel performing fuel reconstitution work was outstanding. Work performed by them was of the highest quality. However, problems were noted regarding QC activities (see section 4.10).

The licensee reorganized the outage management activities for the Unit 3 outage. In order to manage outage activities, daily meetings were held to discuss work status, problems and operational milestones. Rather than having one larger group for all activities the work was divided into smaller and more manageable areas including fuel floor, drywell, reactor systems, and balance of plant. Coordinators were assigned to each area and shift engineers were on site at all times to handle any problems as they arose. The organization for managing outage activities appeared to work well.

The Major Outage Recovery Effort (MORE) team established to coordinate the restoration activities in the Unit 2 drywell and to implement preoperational and system startup testing was well administered and staffed with experienced, competent personnel. Hardware deficiencies identified by the NRC inspectors were already identified and tracked by the MORE team. The startup and preoperational testing of Unit 2 performed by the MORE team was well planned and documented.

Core reload activities for Unit 2 in May 1985 and for Unit 3 in November 1985 were adequately planned and conducted. During the Unit 3 core offloading, a peripheral fuel bundle was isolated from a source range monitor (SRM). The fuel bundle had been omitted in the fuel loading sequence used to offload the core. A temporary procedure change was made to allow continued fuel moves with one inoperable SRM in a quadrant of the core.

In summary, the licensee's refueling and outage activities are well planned and adequately implemented. The refueling and outage organization exhibited sustained excellent performance during the assessment period. Many difficult and unique problems were adequately handled. Good coordination among engineering, construction, maintenance, testing and outage organizations was evident.

Conclusion

Rating: Category 1

Trend: Consistent

Board Recommendations

Licensee: None

NRC: None

4.9 Training and Qualification Effectiveness (N/A)

Analysis

During this assessment period, training and qualification effectiveness is being considered as a separate functional area for the first time. Training and qualification effectiveness continues to be an evaluation criterion for each functional area.

The various aspects of this functional area have been considered and discussed as an integral part of other functional areas and the respective inspection hours have been included in each one. Consequently, this discussion is a synopsis of the assessments related to training conducted in other areas. Training effectiveness has been measured primarily by the observed performance of licensee personnel and, to a lesser degree, as a review of program adequacy. The discussion below addresses three principal areas: licensed operator training, non-licensed staff training, and status of INPO training accreditation.

During the assessment period, resident and specialist inspections routinely reviewed training. Two operator licensing exams were given by region-based examiners. Licensed operator requalification training was reviewed during the Unit 2 team restart inspection. Training was reviewed during programmatic reviews of operations (licensed, non-licensed and requalification), radiation protection, general employee training (GET), general respiratory training (GRT), maintenance, fire protection, emergency preparedness, and chemistry.

The licensee is proceeding with INPO accreditation of training programs. Training programs for Senior Licensed Operators, Licensed Operators, Non-licensed Operators, Chemistry Technicians, and Health Physics Technicians were accredited by INPO in May 1985. The remaining five programs (I&C, Electrical Maintenance, Mechanical Maintenance, Technical Staff and Management, and Shift Technical Advisor) have all been submitted and INPO accreditation visits at Peach Bottom are scheduled in April 1986.

Although the licensed operator training and requalification training programs function well as evidenced by NRC exam performance, a number of personnel errors have resulted in reactor scram signals and ESF actuations. Six scrams can be attributed to errors by licensed operators and two scrams can be attributed to errors by non-licensed operators. Also, four scrams can be attributed to errors by I&C Technicians during surveillance activities.

GET and GRT were reviewed both during resident and specialist inspections. The overall GET and GRT programs appear to be adequate. The effectiveness of an expanded GET and a new "Nuclear Professionalism - Job Orientation" training has not been assessed.

Poor performance during the annual emergency exercise can be attributed to inadequate training. Deficiencies were noted during the previous assessment period in emergency plan training. Based on this deficiency, the licensee accomplished the following: revised lesson plans and hired two experienced contractors to train the staff; and, developed a training matrix to document and track staff training. Although the licensee made progress, emergency plan training was not completed and key managers had not been trained. During the annual emergency exercise, significant problems occurred stemming, in part, from this lack of training. (See Section 4.6)

An improvement in HP and chemistry technician performance during the assessment period was noted. The development and implementation of a five day senior HP technician training program is considered a licensee strength for the overall HP training program. A continuing training program for chemistry technicians was implemented in 1985 and attendance was good.

Maintenance related training, that is conducted prior to actual in-plant job performance, is considered a licensee strength. Reviews were conducted of the mockup training for the Unit 3 core spray sparger repair and of the formal control rod drive (CRD) training. A mockup of the in-vessel core spray sparger piping and the shielded work booth was used to train maintenance personnel prior to the actual work. The mockup training was successful as evidenced by a smooth running maintenance evolution. The licensee has a formal training program for CRD mechanism assembly and disassembly. The training program includes use of an under vessel mockup of a CRD mechanism. The success of the CRD training is evidenced by only minimal problems during the changeout of over 80 CRDs during the Unit 2 and 3 refueling outages. The man-rem doses for the above mentioned maintenance jobs were well below the initial estimates.

Conclusion

Rating: Category 2

Trend: Consistent

Board Recommendations

Licensee: None

NRC: None

4.10 Assurance of Quality (N/A)

Analysis

Management involvement and control in assuring quality continues to be an evaluation criterion for each functional area. During this assessment period, assurance of quality is being considered as a separate functional area.

The various aspects of the programs to assure quality have been considered and discussed as an integral part of each functional area and the respective inspection hours are included in each one. Consequently, this discussion is a synopsis of the assessments relating to the quality of work conducted in other areas.

The previous assessment period highlighted several strengths in the licensee's quality assurance (QA) program primarily associated with engineering activities.

Activities examined during this period included: plant modifications, maintenance, operations, overlay welding, pipe inspections, equipment calibration, worker qualifications, material controls, chemistry, radiation protection, and plant outage recovery.

The offsite review committee, the Nuclear Review Board, is functioning satisfactorily and demonstrates a questioning attitude with regard to safety issues. However, the NRB has not demonstrated effectiveness relative to review and correction of identified lapses in procedural adherence.

The PORC should be more instrumental in improving operational safety particularly in the areas of reduction of personnel errors and improved procedural adherence.

The Independent Safety Engineering Group has been under staffed (1-2 vacancies) and without a permanent on-site supervisor for most of the assessment period. A daily review by ISEG of safety equipment and the effect on plant operations was stopped due to manpower limitations. The daily review had been initiated because of a prior experience with the simultaneous inoperability of a diesel generator and one train of containment cooling, and was a corrective action identified at the Enforcement Conference held on February 8, 1985. The ISEG daily review was resumed only after the commitment was brought to the licensee's attention by the NRC.

The licensee's QA audits of the Unit 2 outage recovery were thorough both from the standpoint of scope of activities and depth of coverage. Management use of the audit program was determined to lack effectiveness during the Unit 2 readiness inspection in that, no provision had been made to perform a final systematic review of open QA/QC problem reports to ensure disposition, as necessary, prior to plant restart. The licensee responded by developing a computerized program called QA Tracking and Trending System (QATTS) which allowed for a systematic review of open problem reports by the QA staff. Open problem report information is provided to the Superintendent - Operations for disposition before plant restart.

QA has not been used effectively to audit the overall emergency preparedness program or the annual exercise. Problem areas identified in the past do not appear to be tracked until fully resolved. For example, the need for precise emergency action levels have been identified in several NRC inspections of annual exercises.

QA oversight of surveillance testing activities was weak in that it did not identify weaknesses in the surveillance program such as the missed or partially completed surveillances, and the lack of procedures regarding actions to be taken relative to overdue surveillance tests.

During the assessment period, quality control (QC) personnel were frequently observed inspecting maintenance and surveillance activities. The QC involvement in control rod drive (CRD) rebuild on both units, diesel generator maintenance, and weld overlay was strong. QC's method of sampling and reviewing local leak rate tests (LLRT) was assessed to be very effective. Both LLRT and containment integrated leak rate testing activities are reviewed in accordance with a detailed monitoring checklist which is specific to the type of test performed. The checklists were judged to be comprehensive and technically useful.

Licensee QC coverage of fuel reconstitution work on Unit 3 was weak. Initially, the only personnel on the refueling floor significantly involved in the fuel reconstitution effort were contractor personnel. QC checks were performed by the workers conducting the fuel reconstitution activity. Licensee management personnel were unaware of the situation. When the problem was brought to management's attention, the licensee separated the QC function from the fuel reconstitution effort.

In summary, based on performance in several functional areas, the focus of established committees and management does not appear directed toward the resolution of operational problems and the assurance of operational quality.

Conclusion

Rating: Category 3

Trend: Consistent

Board Recommendations

Licensee:

-- Consider a management review to determine:

(1) the effectiveness of the several oversight groups and

(2) the extent to which these groups are used to assure that performance improvements are achieved.

NRC: None

4.11 Licensing Activities (NA)

Analysis

The approach used in this evaluation was to select a number of licensing actions which involved a significant amount of staff effort or which were related to important safety or regulatory issues for the SALP performance period. The previous assessment period evaluated licensing activities as Category 1, with a declining trend. The staff noted a trend during that period where management involvement and control did not appear to be fully functional. The trend manifested itself in the noticeable decline in the licensee's usually timely response and resolution of licensing issues and the need to give more attention to the significant hazards consideration determination (Sholly determinations) that were submitted for each Technical Specification change request.

By letter dated July 9, 1985, the licensee responded to the above noted weaknesses of the previous SALP by indicating that their licensing staff had been increased in size and reorganized to improve the response time for licensing issues at Peach Bottom.

Actions considered during the current SALP evaluation include license amendments requests, exemptions and relief requests, responses to Generic Letters, and TMI and Salem (ATWS) items. Fifty-six licensing actions were completed during this evaluation period. A summary of actions active during this period is presented in Table 6. Strong management involvement and attention were especially evident during this period for those issues having potential for substantial safety impact and extended shutdowns; namely, the Unit 3 refueling and pipe inspection program and the proposed re-racking of Unit 2 and 3 spent fuel pools. Management screening of submittals in these two areas was highly apparent since the submittals were consistently clear and of high quality.

Both of these above actions show evidence of the licensee's capability for excellent prior planning, assignment of priorities, and the development of defined procedures to control activities.

However, despite the licensee's steps to respond to the previous SALP recommendations concerning licensing activities, there continues to be evidence of the lack of management attention in the areas of timely resolution of NRC initiatives and the variable quality of Sholly evaluations. Examples of significant delays in follow-up responses by the licensee include resolution of Technical Specifications regarding Appendix J, purge and vent valves, containment cooling, and diesel fuel oil. Concerning Sholly evaluations, overall quality was still highly variable during the report period. Considerable NRC staff attention was required prior to Federal Register publication on most Technical Specification change requests.

As indicated in the previous SALP, it was noted that a declining trend overall existed for licensing activities involving the Peach Bottom facility. As pointed out above, the same licensing weaknesses identified during the last assessment period remain basically uncorrected. Therefore, although the licensee has provided excellent and timely resolution for certain select actions during this report period, the NRC staff continues to face a long-standing backlog of licensing actions requiring licensee follow-up before they can be resolved.

Conclusion

Rating: Category 2

Trend: Consistent

Board Recommendations

Licensee: None

NRC:

-- NRR Project Manager to meet at least quarterly with the licensee to discuss licensing issues (i.e., backlogs, problems, schedules, and projected workloads)

V. SUPPORTING DATA AND SUMMARIES

5.1 Investigations and Allegations Review

Three allegations were received during the assessment period:

-- unqualified personnel sent to Peach Bottom to perform QC functions

-- potential overexposure during Unit 3 offgas pipe tunnel release

-- alleger fired for talking to NRC

5.2 Escalated Enforcement Actions

1. Civil Penalties

   Civil Penalty of $25,000.00 associated with NRC Inspection 277/85-11 conducted during period February 13 - 15, 1985 (previous assessment period). The violations were associated with radiation protection practices during the Unit 2 pipe replacement outage. The Notice of Violation and Civil Penalty were combined with escalated enforcement from Limerick (Enforcement Action #85-42 dated June 7, 1985).

2. Orders

   None

3. Confirmatory Action Letters (CAL)

   CAL dated November 5, 1985, regarding actions to be taken by PECo in the area of Peach Bottom emergency preparedness. (See section 4.6).

4. Enforcement Conferences

   -- May 13, 1985; Security violations

   -- June 21, 1985; Apparent inattentive Unit 3 reactor operator

   -- November 14, 1985; Radwaste transportation activities and recent violations

5.3 Management Conferences Held During the Assessment Period

-- June 12, 1985; SALP management meeting

-- August 1, 1985; Status of the Peach Bottom June 18, 1984 Order

-- October 23, 1985; PECo Maintenance Division meeting

5.4 Licensee Event Reports (LERs)

1. Causal Analysis

Fifty LERs were submitted during the assessment period for Units 2 and 3. The LERs are characterized by cause for each functional area in Table 1. Causally-linked event sets were identified.

LER Number

2-85-06 3-85-17 3-85-21 3-85-30	--	RPS actuations during shutdown caused when IRM cables were bumped in the subpile room (see Table 5A) due to personnel work practices.
2-85-04 2-85-07 2-85-09 2-85-10 2-85-15 2-85-16	--	RPS and ESF actuations caused due to I&C technician errors with the instrument backfilling equipment and improper valving of instruments.
2-85-11 2-85-25	--	RPS actuations during turbine testing.
3-85-16 3-85-19 3-85-24 3-85-26	--	ESF actuations due to personnel errors associated with testing and installing blocking permits.
3-85-13 3-85-13, Revision 1 3-85-14 3-85-20	--	Unit 3 piping cracks and IGSCC indications in reactor components.

2. AEOD Review

The Office for Analysis and Evaluation of Operational Data (AEOD) assessed the Licensee Event Reports (LERs). The review covered fifteen LERs submitted during the assessment period. The LERs submitted were adequate in each important respect with few exceptions. The LERs provided clear descriptions of the cause and nature of the events as well as adequate explanations of the effects on both system function and public safety. The described corrective actions taken or planned by the licensee

were considered to be commensurate with the nature, seriousness and frequency of the problems found. Table 1 provides a tabular listing of the LERs versus functional area.

The evaluation of the content and quality of a representative sample of LERs submitted by Peach Bottom 2 and 3 during the April 1, 1985 to January 31, 1986 SALP period was performed using a refinement of the basic methodology presented in NUREG/CR-4178. The results of this evaluation indicate that Peach Bottom 2 and 3 submitted above average LERs.

The principle weaknesses identified, in terms of plant safety significance, involves the safety consequence discussions. The deficiency in the safety consequence discussion concerns whether events are being evaluated such that the possible consequences of the event, had it occurred under a different set of initial conditions, are identified.

Another observation resulting from the evaluation involves the numbering of LERs. Two LERs for Unit 2 were numbered the same even though they were different events (i.e., LER 2-85-06).

In summary, the LERs indicate that the licensee provided adequate descriptions of the events. None of the LERs reviewed by AEOD involved a significant event or serious challenge to plant safety.

5.5 Automatic Scrams and Unplanned Shutdowns

1. During the assessment period, 19 automatic scrams and three unplanned shutdowns occurred on Unit 2.

2. During the assessment period, 13 automatic scrams occurred on Unit 3.

Table 5 summarizes all automatic scrams and unplanned shutdowns.

TABLE 1
TABULAR LISTING OF LERs BY FUNCTIONAL AREA
PEACH BOTTOM ATOMIC POWER STATION

Area	Number/Cause Code						Total
	A	B	C	D	E	X	
1. Plant Operations	17	1	1	3	1	1	24
2. Radiological Controls							0
3. Maintenance	1				2	5	8
4. Surveillance					2	3	5
5. Fire Protection	2	2					4
6. Emergency Preparedness							0
7. Security and Safeguards							0
8. Refueling/Outage Activities	4					4	8
9. Training							0
10. Quality Assurance		1					1
11. Licensing Activities							0
TOTALS	24	4	1	3	5	13	50

Cause Codes:
- A - Personnel Error
- B - Design, Manufacturing, Construction, or Installation Error
- C - External Cause
- D - Defective Procedure
- E - Component Failure
- X - Other

TABLE 2
VIOLATION SUMMARY (4/1/85 - 1/31/86)
PEACH BOTTOM ATOMIC POWER STATION

A. NUMBER AND SEVERITY LEVEL OF VIOLATIONS

	Number of Violations
Severity Level I	0
Severity Level II	0
Severity Level III	4
Severity Level IV	11
Severity Level V	2
Total	17

B. VIOLATIONS VS. FUNCTIONAL AREA

Functional Area	Severity Level III	IV	V	Totals
1. Plant Operations	0	3	0	3
2. Radiological Controls	4	0	1	5
3. Maintenance	0	0	0	0
4. Surveillance	0	3	0	3
5. Fire Protection/Housekeeping	0	0	0	0
6. Emergency Preparedness	0	0	0	0
7. Security and Safeguards	0	4	0	4
8. Refueling/Outage Activities	0	0	1	1
9. Training	0	0	0	0
10. Quality Assurance	0	1	0	1
11. Licensing Activities	0	0	0	0
Total	4	11	2	17

C. SUMMARY LISTING

Inspection Report No.	Inspection Date	Severity Level	Functional Area	Violation(s)
277/85-12 278/85-12	March 16 - May 10, 1985	IV	Operations	Failure to follow procedures for Shift Supervisor relief and for checking seismic restraints
277/85-16 278/85-13	April 14-18, 1985	IV	Security	(1) Failure to report changes in security program
		IV	Security	(2) Failure to post guard for access control to drywell
		IV	Security	(3) Failure to wear photo ID badge in protected area
		IV	Security	(4) Failure to respond to vital area alarms
278/85-23	June 4-13, 1985	IV	Surveillance	Failure to adequately test containment isolation valves
277/85-27 278/85-25	May 30, 1985	III	Radiological Controls	Radwaste drum shipped to facility with hole
277/85-29 278/85-33	September 14 - October 25, 1985	IV	Surveillance	(1) Failure to perform ST on portal monitor
		IV	Surveillance	(2) Failure to perform ST on Unit 3 SRVs
		IV	Operations	(3) Failure to make 50.72 and 50.73 notifications

Inspection Report No.	Inspection Date	Severity Level	Functional Area	Violation(s)
		IV	Operations	(4) Failure to adhere to equipment blocking (tagout) procedures
277/85-31 278/85-28	July 29 - August 1, 1985	III	Radiological Controls	(1) Failure to include accurate activities in shipping papers
		III	Radiological Controls	(2) Contamination on exterior surface of FSV-1 cask
		V	Radiological Controls	Improper certification on radwaste shipment manifest
278/85-32	September 9-13, 1985	IV	Quality Assurance	Failure to implement QA program requirements
278/85-32	September 9-13, 1985	V	Refueling Outage	Failure to comply with written HP and QC procedures
277/85-39 278/85-40	October 18, 1985	III	Radiological Controls	Improperly attached pallet lifting cables

TABLE 3
INSPECTION REPORT ACTIVITIES (4/1/85 - 1/31/86)
PEACH BOTTOM ATOMIC POWER STATION

Report Number Unit 2	Report Number Unit 3	Inspection Hours	Areas Inspected
85-12	85-12	339	Resident Operational Safety
85-15		274	Unit 2 Restart Team Inspection
85-16	85-13	8	Security/Safeguards
85-17		36	Unit 2 Local Leak Rate Testing
85-19	85-15	12	Dosimetry
85-21	85-17	248	Resident Operational Safety
85-18	85-18	None	Operator Licensing Exams
85-22	85-19	None	Operator Licensing Exams
85-23	85-23	54	Unit 2 Integrated Leak Rate Testing
85-24	85-20	76	Emergency Preparedness
85-25	85-21	275	Resident Operational Safety
	85-22	10	Inattentive Unit 3 Operator
85-26		74	Unit 2 Startup Testing
85-27	85-25	4	Radwaste Shipping
85-28	85-26	140	Health Physics and Chemistry Team Special Inspection
85-29	85-33	297	Resident Operational Safety
85-30	85-27	296	Resident Operational Safety
85-31	85-28	33	Radwaste Shipping
85-32	85-29	80	Security/Safeguards

Report Unit 2	Unit 3	Inspection Hours	Areas Inspected
85-33	85-30	118	Electrical and I&C Maintenance Programs
	85-31	20	Health Physics Allegation Followup
	85-32	41	Unit 3 Fuel Reconstitution
85-34	85-14	133	Generic Letter 84-11 and IGSCC
85-35	85-34	310	Emergency Preparedness Annual Exercise
	85-35	72	Unit 3 Local Leak Rate Testing
	85-36	28	Health Physics for Unit 3 Core Spray Sparger Repair and Low Level Radwaste Facility
85-37	85-38	33	Safeguards Material Control & Accountability
85-38	85-37	42	Unit 3 Core Spray Sparger Repair and Weld Overlays
	85-39	91	Alternate Safe Shutdown Modifications
85-39	85-40	6	Radwaste Shipping
	85-41	245	Resident Operational Safety and Unit 3 Restart Team Inspection
85-40		223	Resident Operational Safety
85-41		13	Followup On Radwaste Fire
85-42	85-42	15	Radwaste Enforcement Conference
85-43	85-43	42	Security/Safeguards

Report Unit 2	Unit 3	Inspection Hours	Areas Inspected
85-44	85-44	291	Resident Operational Safety
86-01	86-01	36	Radiological Effluents
86-02		78	Health Physics Training
	86-02	67	Unit 3 Integrated Leak Rate Testing

TABLE 4
INSPECTION HOURS SUMMARY (4/1/85 - 1/31/86)
PEACH BOTTOM ATOMIC POWER STATION

Functional Area	Hours	% of Time
4.1 Plant Operations	1300	31.3
4.2 Radiological Controls	495	11.9
4.3 Maintenance	367	8.8
4.4 Surveillance	483	11.6
4.5 Fire Protection	173	4.3
4.6 Emergency Preparedness	431	10.4
4.7 Security and Safeguards	238	5.7
4.8 Refueling/Outage Activities	666	16.0
4.9 Training**	0	0
4.10 Quality Assurance**	0	0
4.11 Licensing Activities*	0	0
TOTAL	4153	100%

*Hours expended are not included with direct inspection effort statistics.

**Hours expended in training and quality assurance are included in other functional areas.

TABLE 5
LISTING OF ALL AUTOMATIC SCRAM SIGNALS & UNPLANNED SHUTDOWNS
PEACH BOTTOM ATOMIC POWER STATION
Unit 2 (4/1/85 thru 1/31/86)

No.	Date	Power Level	Description	Cause	Note 1
1	5/30/85	SD	Scram signal from high pressure while in cold shutdown (NO ROD MOVEMENT) during hydro and excess flow check valve testing. Pressure increased due to test personnel stopping leak concurrent with operator actions to raise pressure. (LER 2-85-02)	Personnel error - reactor operator	
2	6/22/85	SD	Scram signal when reactor level transmitter was valved into service too quickly causing false low level while in cold shutdown (NO ROD MOVEMENT). (LER 2-85-04)	Personnel error - I&C technician	
3	6/22/85	SD	Scram signal when reactor level transmitter was being backfilled with water. Incorrect operation of the backfilling assembly caused a false low level signal while in cold shutdown (NO ROD MOVEMENT). (LER 2-85-04)	Personnel error - I&C technician	
4	6/27/85	SD	Scram signal from two IRMs while in cold shutdown (NO ROD MOVEMENT) while working in subpile room, maintenance personnel inadvertently bumped two IRM voltage cables causing a full scram signal. (LER 2-85-06)	Personnel work practices	
5	6/28/85	SD	Same as #3 above. (LER 2-85-07)		
6	6/28/85	SD	Same as #3 above. (LER 2-85-07)		
7	6/29/85	SD	Same as #3 above. (LER 2-85-09)		
	7/6/85		Startup from outage		

Note 1 - Determined by SALP Board, may not agree with LER analysis.

* Scrams with Rod Movement

No.	Date	Power Level	Description	Cause
8*	8/5/85	100%	Scram due to turbine control valve (TCV) closure while testing at 100% power. EHC pressure experienced a normal momentary decrease during TCV #3 testing combined with set-point drift of TCV #4 pressure switch that actuates scram. The low pressure trip of both TCV #3 and #4 caused a full scram. (LER 2-85-11)	Equipment failure - random setpoint drift
	8/7/85		Startup	
9*	8/7/85	2%	High IRM scram at 2% power during unit startup. Reactor operator withdrew a high worth rod two notches during startup mode to control reactor pressure with EHC out of service. He failed to uprange switches and an IRM high-high scram occurred. (LER 2-85-12)	Personnel error - reactor operator
	8/8/85		Startup	
10	8/12/85		Shutdown required by TS due to simultaneous inoperability of the E-3 DG and RHR loop A (MOV RHR 154A). (LER 2-85-13)	Inadequate maintenance spare parts
	8/14/85		Startup	
11	8/19/85		Same as #10 above, except E-2 DG inoperable.	
12	8/20/85	SD	Low level scram signal while in hot shutdown (NO ROD MOVEMENT) during plant cooldown. Actual low level occurred due to slow response of level controller, combined with inattention of reactor operator during level swings. (LER 2-85-14)	Personnel error - reactor operator

No.	Date	Power Level	Description	Cause
13	8/22/85	SD	False low level scram signal while in cold shutdown while in cold shutdown while testing a pressure transmitter (NO ROD MOVEMENT). A leaking instrument isolation valve resulted in a pressure spike on the level sensing lines resulting in full RPS actuation. (LER 2-85-15)	Equipment failure - random
	8/26/85		Startup	
14*	8/26/85	5%	Low level scram from 5% power during plant startup when a pressure transmitter was incorrectly returned to service by an operator. The resulting false low level caused by pressure spikes on the sensing lines caused a scram. (LER 2-85-16)	Personnel error - non licensed operator
	8/26/85		Startup	
15	9/19/85		Shutdown required by TS due to simultaneous inoperability of the 2A RHR pump and the E-2 DG. (LER 2-85-19)	Low flow due to unmodified impeller
16	9/24/85	SD	Low level scram signal while in cold shutdown (NO ROD MOVEMENT). Operator incorrectly aligned RHR while in shutdown cooling, causing an actual low level as the vessel drained to the torus. The operator did not follow the procedure. (LER 2-85-20)	Personnel error - reactor operator
	10/4/85		Startup	
17*	10/17/85	100%	Low level scram from 100% power due to loss of feedwater when all RFPs tripped, caused by a faulty connector on the total flow summer in the reactor feedwater level control system. (LER 2-85-22)	Equipment failure - random

No.	Date	Power Level	Description	Cause
	10/18/85		Startup	
18*	11/29/85	31%	Scram from 31% power due to turbine stop valve closure with inadequate control of troubleshooting by operators. The reactor operator's misunderstanding of control room alarms regarding scram bypasses contributed to the scram. (LER 2-85-25)	Personnel error - operations
	12/24/85		Startup	
19*	12/26/85	44%	Scram from 44% power due to low level during reactor feedwater system transient. A combination of feedwater control and RFP equipment problems combined with licensed operators swapping RFPs at power resulting in a water hammer in feedwater system and loss of RFPs. (LER 2-85-27)	Personnel error - reactor operator
	12/29/85		Startup	
20*	1/1/86	90%	Scram from 90% power due to turbine trip caused by moisture separator high level trip. A combination of a faulty moisture separator drain valve and a non-licensed operator personnel error causing the dump valve to close resulted in a high level trip. (LER 2-86-01)	Personnel error - operations
	1/2/86		Startup	
21*	1/24/86	95%	APRM high scram from 95% power caused by high reactor pressure when the E-2 DG tripped (half scram) when carrying an RPS bus, and 2 MSIVs closed due to DC solenoid failures. (LER 2-86-03)	Multiple random equipment failures - design

22	1/24/86	SD	Voltage transient on #2 startup source when 2A recirc MG set started causing a voltage dip in 2B RPS logic power supply on alternate feed resulting in loss of power to SDV high level bypass relays. Since the SDV level was high due to an actual scram (see #21 above), a second full scram signal occurred. (LER 2-86-04)	Equipment failure - design

Unit 3 (4/1/85 thru 1/31/86)

No.	Date	Power Level	Description	Cause
1	8/26/85	SD	Scram signal with no fuel in the reactor vessel (NO ROD MOVEMENT) when worker bumped one IRM cable in subpile room. Scram occurred because one RPS channel was out of service (tripped) due to relay maintenance and IRM tripped the other RPS channel. (LER 3-85-21)	Personnel work practices - maintenance
2	8/28/85	SD	Same as #1 above.	
3	8/29/85	SD	Same as #1 above.	
4	9/11/85	SD	Same as #1 above.	
5	9/11/85	SD	Similar to #1 above except worker bumped SDV high level switch and scram due to SDV level high. (LER 3-85-22)	Personnel work practices - maintenance
6	9/12/85	SD	Same as #1 above.	
7	9/13/85	SD	Same as #1 above.	
8	9/13/85	SD	Same as #1 above.	
9	9/14/85	SD	Same as #1 above.	
10*	10/10/85	SD	Same as #1 above except two IRMs were bumped and some rod movement occurred. The control rods were withdrawn with core defueled for ALARA considerations during core spray sparger work.	
11	10/18/85	SD	Scram signal with no fuel in the reactor vessel (NO ROD MOVEMENT) when engineer removed jumpers from the RPS logic in accordance with special procedure. A half-scram was already present due to maintenance on one RPS channel. The procedure did not provide a caution when half scram was already present. (LER 3-85-16)	Control of work activities

No.	Date	Power Level	Description	Cause
12	10/18/85	SD	Same as #1 above. (LER 3-85-17)	
13	12/17/85	SD	Same as #1 above, except the reactor core was loaded and in cold shutdown. (LER 3-85-30)	

TABLE 6
NRR SUPPORTING DATA AND SUMMARY
PEACH BOTTOM ATOMIC POWER STATION

1. NRR/Licensee Meeting/Site Visits

Site Visits: June 12, 1985; November 21, 1985
Meetings:
05/13/85: SALP Board Meeting
05/30/85: "Energy Absorbers"
06/14/85: SPDS
09/05/85: Unit 3 Pipe Cracks
09/17/86: Unit 3 Core Spray Sparger Cracks
10/01/85: Unit 3 Cracks in Safe Ends
10/31/85: N-1 Safe Ends
12/19/85: Cracks in Shroud Head Bolts and Wear Rings

2. Commission Meetings
None

3. Scheduler Extensions Granted
08/05/85; submittal of DCRDR Summary Report

4. Relief Granted
05/14/85; ISI Relief

5. Exemptions Granted
None

6. License Amendments Issued

Amendment Nos. 109, 112 issued June 6, 1985; approves miscellaneous TS changes
Amendment Nos. 110, 113 issued July 17, 1985; approves 50.72 & 50.73 reporting requirements
Amendment Nos. 111, 115 issued October 2, 1985; approves correction of set points of Emergency Plan Test Frequency
Amendment No. 114 issued August 23, 1985; Unit 3 Reload
Amendment Nos. 112, 116 issued November 19, 1985; approves changes in coolant leakage detection systems
Amendment Nos. 113, 117 issues November 19, 1985; Nureg-0737 TS
Amendment Nos. 114, 118 issued November 22, 1985; revised certain portions of RETS

7. Emergency/Exigent Technical Specifications
None

8. Orders Issued
None

9. NRR/Licensee Management Conferences
None

Figure 1

Unit 2 - Number of Days Shutdown

PEACH BOTTOM ATOMIC POWER STATION

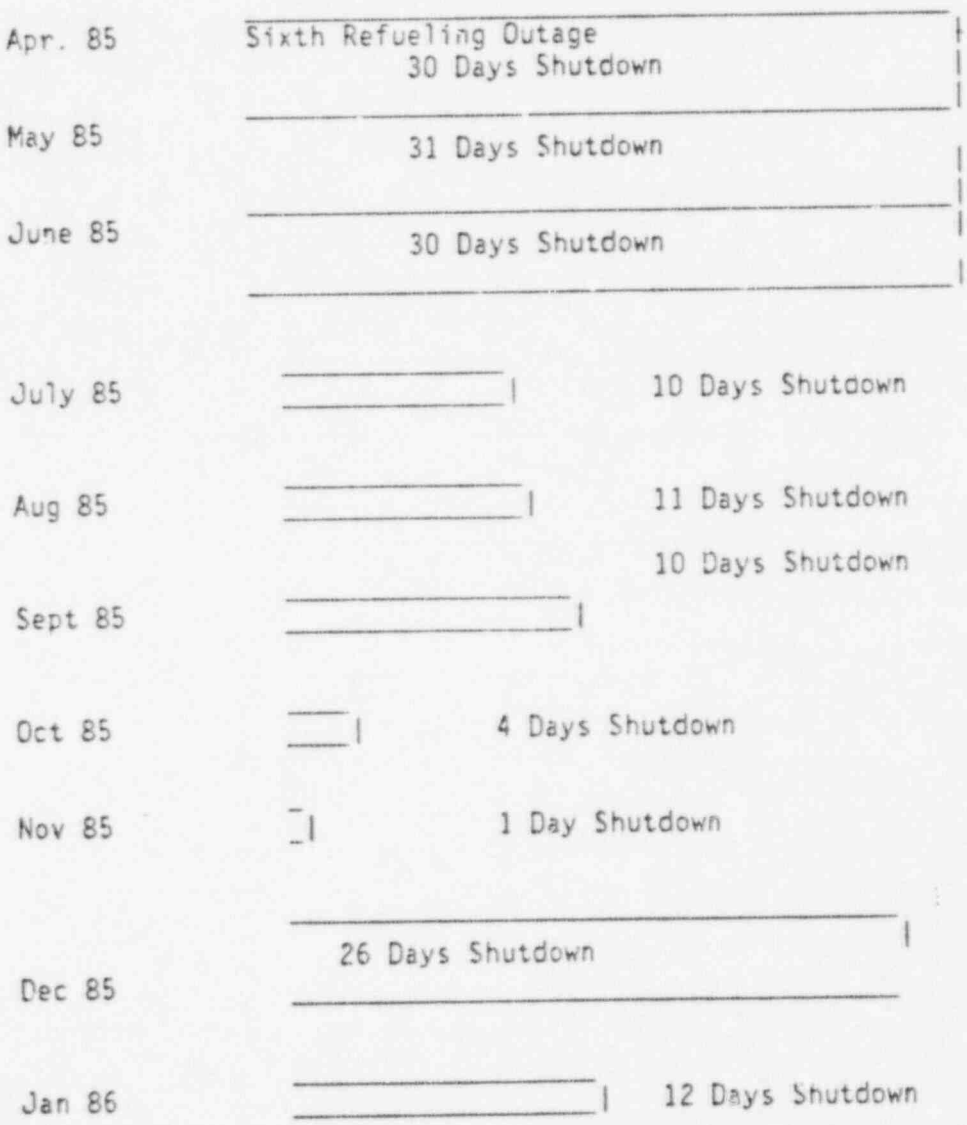

Figure 2

Unit 3 - Number of Days Shutdown

PEACH BOTTOM ATOMIC POWER STATION