JUN 6 1985

Docket No. 50-277

MEMORANDUM FOR: Gus C. Lainas, Assistant Director
for Operating Reactors
Division of Licensing

FROM: William V. Johnston, Assistant Director
Materials, Chemical and Environmental Technology
Division of Engineering

SUBJECT: REVIEW OF PEACH BOTTOM UNIT 2 JUSTIFICATION FOR CONTINUED OPERATION (TACS #55606, #55576, AND #55174)

The Philadelphia Electric Company (PECO) transmitted a report dated April 15, 1985 for NRC review. The submittal provides a justification for continued operation of Peach Bottom Unit 2 following the completion of the current outage. At NRC's request, PECO submitted additional information on May 14, 1985 regarding the disposition of nonconforming welds that were not replaced during this outage.

The Materials Engineering Branch, Division of Engineering, has reviewed this information and has concluded that Peach Bottom Unit 2 can be safely returned to full power operation. Our conclusion is based on the following considerations.

(1) Except for seven welds, PECO has replaced all the nonconforming piping in the recirculation, residual heat removal (RHR), RHR head spray, reactor water cleanup and core spray systems in Peach Bottom Unit 2. The piping replacement also includes two jet pump instrument seals and ten recirculation inlet nozzle safe-ends and associated thermal sleeves, which were found to be cracked during this outage. The replacement piping material is low carbon (<0.02%) Type 316 stainless steel, which is considered to be resistant to intergranular stress corrosion cracking (IGSCC).

(2) The piping replacement was carried out in accordance with the provisions in 10 CFR 50.59 and the guidelines in Generic Letter 84-07. NRC Region I has closely monitored the piping replacement activities including reviewing the procedures used in piping installation, welding and preservice inspection, and is satisfied with all the piping replacement activities. Region I's input regarding PECO's piping replacement is attached.

Contact: W. Koo
X-28589

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

November 16, 1993

Docket No. 50-278

Mr. George A. Hunger, Jr.
Director-Licensing, MC 52A-5
Philadelphia Electric Company
Nuclear Group Headquarters
Correspondence Control Desk
P. O. Box No. 195
Wayne, Pennsylvania 19087-0195

Dear Mr. Hunger:

SUBJECT: CRACKING IN SEGMENT OF CORE SPRAY PIPING, PEACH BOTTOM ATOMIC POWER STATION (PBAPS), UNIT 3 (TAC NO. M88098)

This letter responds to your November 5, 1993, and November 10, 1993, letters in which you forwarded an evaluation of a 3-inch crack you identified in a segment of core spray piping located between the inlet nozzle and the vessel shroud in PBAPS, Unit 3. Your submittals were in accordance with the actions requested by IE Bulletin 80-13, "Cracking in Core Spray Spargers." IE Bulletin 80-13 requests that licensees submit an evaluation for NRR review and approval prior to return to operation, if they identify cracking in the core spray sparger system.

The NRR staff has reviewed your submittals and determined that your evaluation is acceptable for the next cycle of operation for the following reasons (the staff verbally approved your return to operations during a November 10, 1993 conference call):

1) ~~Piping integrity is expected to be maintained for all conditions including loss-of-coolant accident (LOCA).~~

2) In the event piping integrity is lost, your analysis determined that the sleeved piping arrangement will ensure that adequate core spray flow is maintained to ensure that the requirements of 10 CFR 50.46 remain satisfied.

3) In the unlikely event the B core spray loop fails completely, a more realistic analysis determined that adequate core cooling is assured during a LOCA.

4) There is no safety concern with loose parts.

5) ~~During the November 10, 1993, conference call, you committed to repairing the crack during the next refueling outage (the repair method will be determined later). You also committed to revise your submittal to explicitly state that pipe whip and cold water jet impingement will not compromise the integrity of the reactor vessel in the event of a guillotine break of the core spray piping during LOCA. You further committed to maintain the analysis that suppo[rts] this statement on site for NRC's review.~~

9311300115 4PP

Should you have any questions please contact me at (301) 504-1422.

Sincerely,

Stephen Dembek

Stephen Dembek, Project Manager
Project Directorate I-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

cc: See next page

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Mr. John Doering, Chairman
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Should you have any questions please contact me at (301) 504-1422.

Sincerely,

/S/

Stephen Dembek, Project Manager
Project Directorate I-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

cc: See next page

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Station Support Department

PECO ENERGY

IEB 80-13

PECO Energy Company
Nuclear Group Headquarters
965 Chesterbrook Boulevard
Wayne, PA 19087-5691

October 9, 1995

Docket No. 50-278

License No. DPR-56

U.S. Nuclear Regulatory Commission
Attn: Document Control Center
Washington, DC 20555

Subject: Peach Bottom Atomic Power Station, Unit 3
Core Spray In-Vessel Piping

References:
1) Letter from G. A. Hunger, Jr. (PECO Energy) to U.S. Nuclear Regulatory Commission dated November 5, 1993
2) Letter from G. A. Hunger, Jr. (PECO Energy) to U.S. Nuclear Regulatory Commission dated November 10, 1993
3) Letter from S. Dembeck (NRC) to G. A. Hunger, Jr. (PECO Energy) dated November 16, 1993
4) Letter from G. A. Hunger, Jr. (PECO Energy) to U.S. Nuclear Regulatory Commission dated December 8, 1993
5) Letter from G. A. Hunger, Jr. (PECO Energy) to U.S. Nuclear Regulatory Commission dated June 13, 1995
6) Letter from G. A. Hunger, Jr. (PECO Energy) to U.S. Nuclear Regulatory Commission dated September 28, 1995

Dear Sir:

The purpose of this letter is to identify PECO Energy's corrective actions associated with crack indications identified in the Peach Bottom Atomic Power Station (PBAPS), Unit 3 Core Spray (CS) system, and to request NRC approval to resume operation. This letter is submitted in accordance with IE Bulletin 80-13, "Cracking in Core Spray Spargers," which requests that licensees submit an evaluation of crack indications for NRC approval, prior to returning to operation.

The PBAPS, Unit 3 CS system consists of four downcomers in the reactor vessel, two downcomers per loop. In References 1 and 2, PECO Energy provided the NRC with details and an evaluation of a crack indication on the "D" CS downcomer. This crack indication was identified during refueling outage 3R09. NRC approval for one cycle of operation was provided in Reference 3. Additional information was provided in Reference 4. In References 5 and 6, PECO Energy provided proposed actions associated with the crack indication on the "D" downcomer. As stated in Reference 6, however, PECO Energy indicated that the proposed actions would be reassessed if the visual examination to be conducted during 3R10 revealed cracking beyond what was projected.

During the current refueling outage 3R10, visual examinations identified additional crack indications on the "A" and "C" downcomers. Subsequently, ultrasonic (UT) examinations were performed on all four CS downcomers. These examinations also identified cracking on the "B" downcomer. The cracks on all four downcomers are located on the outer sleeve of a sleeved-pipe connection. Specific details of the UT examinations were discussed with the NRC during an October 6, 1995 telephone call, and are included in the Attachment to this letter.

PECO Energy will be installing a repair clamp on each of the four CS downcomers. This repair modification was reviewed in accordance with 10 CFR 50.59. A previous revision of the modification package was reviewed by the NRC and documented in Inspection Report 50-277/95-18 and 50-278/95-18.

Based on completion of the modification, PECO Energy requests NRC approval to resume operation. Because the modification installs a permanent repair for each of the identified cracks, PECO Energy requests that approval not be limited to a specific cycle of operation.

The Plant Operations Review Committee has reviewed this request. As indicated in previous discussions, resolution of this issue is critical path with respect to completing the current refueling outage. Accordingly, your prompt response is appreciated.

If you have any questions please feel free to contact us.

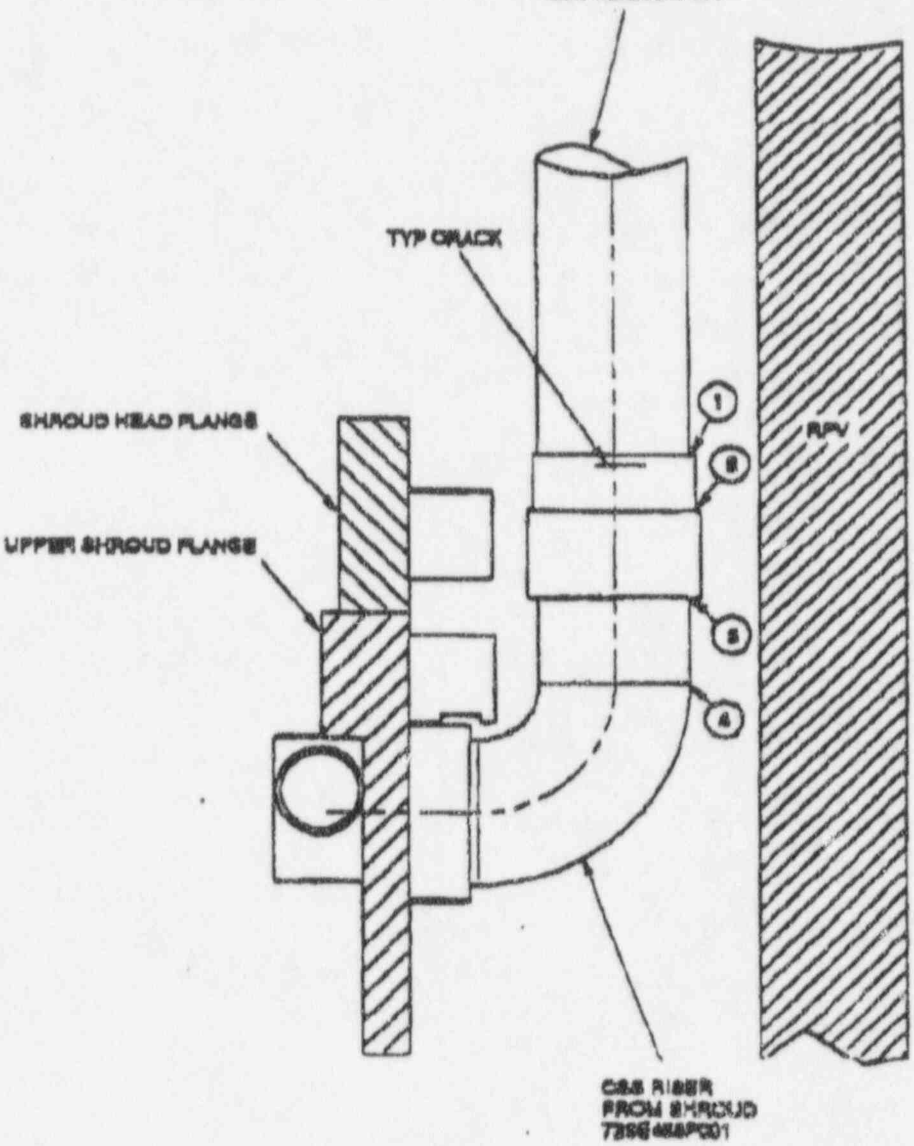
G. A. Hunger, Jr.

G. A. Hunger, Jr., Director
Licensing

Attachment

cc: T. T. Martin, Administrator, Region I, USNRC
W. L. Schmidt, USNRC Senior Resident Inspector, PBAPS

PEACH BOTTOM ATOMIC POWER STATION, UNIT 3
CORE SPRAY DOWNCOMER



DOWNCOMER	CORE SPRAY LOOP	CRACK LENGTH (APPROX. DEG.)*
A (AZ 352.5°)	A	180
B (AZ 7.5°)	B	128
C (AZ 187.5°)	A	280
D (AZ 172.5°)	B	250

* Not continuous, summation of total crack lengths.

PECO ENERGY

PECO Energy Company
Nuclear Group Headquarters
965 Chesterbrook Boulevard
Wayne, PA 19087-5691

October 12, 1995

Docket No. 50-278

License No. DPR-56

U.S. Nuclear Regulatory Commission
Attn: Document Control Center
Washington, DC 20555

Subject: Peach Bottom Atomic Power Station, Unit 3
Core Spray In-Vessel Piping

References:

1) Letter from G. A. Hunger, Jr. (PECO Energy) to U.S. Nuclear Regulatory Commission dated November 5, 1993

2) Letter from G. A. Hunger, Jr. (PECO Energy) to U.S. Nuclear Regulatory Commission dated November 10, 1993

3) Letter from S. Dembeck (NRC) to G. A. Hunger, Jr. (PECO Energy) dated November 16, 1993

4) Letter from G. A. Hunger, Jr. (PECO Energy) to U.S. Nuclear Regulatory Commission dated December 8, 1993

5) Letter from G. A. Hunger, Jr. (PECO Energy) to U.S. Nuclear Regulatory Commission dated June 13, 1995

6) Letter from G. A. Hunger, Jr. (PECO Energy) to U.S. Nuclear Regulatory Commission dated September 28, 1995

7) Letter from G. A. Hunger, Jr. (PECO Energy) to U.S. Nuclear Regulatory Commission dated October 9, 1995

Dear Sir:

The purpose of this letter is to provide additional details in support of the NRC's review of PECO Energy's corrective actions associated with crack indications identified in the Peach Bottom Atomic Power Station (PBAPS), Unit 3 Core Spray (CS) system, and the NRC's verbal approval to return to operation from refueling outage 3R10. The corrective actions, and PECO Energy's request for NRC approval to resume operation were submitted in Reference 7. This request was made in accordance with the requirements of IE Bulletin 80-13, "Core Spray Cracking." Additional information associated with this issue was provided in References 1 through 6.

As stated in Reference 7, PECO Energy will be installing a repair clamp on each of the four CS downcomers. This work is currently in progress, and will be completed prior to returning to operation from the current refueling outage. This repair modification was reviewed in accordance with 10 CFR 50.59. Attachment 1 to this letter includes the 10 CFR 50.59 evaluation and the supporting references. Attachment 2 to this letter provides PECO Energy's response to the NRC's request for additional information.

Based on completion of the modification, the NRC granted verbal approval to return to operation from the current refueling outage. Because the modification installs a permanent repair for each of the identified cracks, the approval was not limited to a specific cycle of operation; however, PECO Energy will continue to visually examine the Core Spray piping in accordance with the guidance in IE Bulletin 80-13. These examinations will continue to monitor the condition of welds and piping material that are not repaired as a result of the installation of the four clamps.

If you have any questions please feel free to contact us.

G.A. Hunger, Jr.

G. A. Hunger, Jr., Director
Licensing

Attachments

cc: T. T. Martin, Administrator, Region I, USNRC
W. L. Schmidt, USNRC Senior Resident Inspector, PBAPS

10CFR50.59 REVIEW for MODIFICATION P00335
INSTALLATION of CORE SPRAY LINE DOWNCOMER CLAMPS
in Peach Bottom Atomic Power Station Unit 3

I. SUBJECT

This 10CFR50.59 Review addresses the modification to repair of core spray line downcomers at the 7.5 degree, 172.5 degree, 187.5 degree and 352.5 degree shroud penetration locations.

During Peach Bottom Unit 3 1993 refueling outage 3R09 inspections performed in response to USNRC IE Bulletin No. 80-13, identified a crack indication on the 172.5 degree core spray line downcomer. Additional crack indications were found during the 1995 refueling outage 3R10 on the 7.5, 187.5 and 352.5 degree downcomers. The crack indications are located in the vertical section (downcomer) of the core spray line outside the shroud but inside the Reactor Pressure Vessel (RPV) where the downcomer pipe is connected to a welded sleeve. The indications run circumferentially in the Heat Affected Zone (HAZ) of the pipe sleeve where the sleeve is welded to the downcomer line. The location of the indications are shown in Figure 1. Ultrasonic inspection of the cracks have characterized the indications as follows:

DOWNCOMER	CORE SPRAY LOOP	CRACK LENGTH (APPROX. DEG.)*
A (AZ 352.5°)	A	180
B (AZ 7.5°)	B	128
C (AZ 187.5°)	A	280
D (AZ 172.5°)	B	250

* Not continuous, summation of total crack lengths.

A repair by modification was designed that addresses the identified crack indications (below weld 1, Figure 1) on the 7.5 degree, 172.5 degree, 187.5 degree and 352.5 degree azimuths. The repair at 172.5 degree azimuth also envelops welds 2, 3 & 4 of Figure 1. The additional design features for the 172.5 azimuth clamp were included prior to 3R10 in vessel inspections to envelop weld locations associated with the downcomer repair on a contigency basis.

The function of the modification is to ensure the structural integrity of the Core

Spray (CS) downcomer even if the identified defects in the HAZ below weld 1 were to grow to the full circumference of the sleeve. Additionally, for the 'D' downcomer the repair assures structural integrity with cracks at weld locations 2, 3 and 4. The modification adds a two clamp design at the 'D' downcomer and a one clamp designs at the 'A', 'B' and 'C' downcomers in the area where the downcomer joint to the shroud inlet is located. The repairs are shown conceptually in Figure 2 (172.5 degree) and Figure 3 (7.5, 187.5 and 352.5 degree). The upper clamp bears on the top of the sleeve that attaches the core spray downcomer to the core spray sparger inlet pipe. A rod locates and supports the lower clamp from the upper. The lower clamp is centered over the inlet pipe to elbow weld joint. A U-bolt that attaches to the upper clamp provides axial restraint between the sleeve and elbow, spanning the crack location(s). The proposed modification is designed so as not to interfere with the potential shroud stabilizer installation or with normal reactor servicing activities.

The proposed change is permanent. The change is designed for a 40 year plant life, using the ASME Boiler and Pressure Vessel Code, Subsection NG (1989 Edition) as a guide for design and analysis. Repair clamp hardware is classified as safety-related, and is designed to current accepted standards. Therefore, it can withstand the same design bases loads as the current core spray line downcomer under normal and abnormal operating conditions. The installation of this hardware will not affect (degrade) other RPV internals.

This review demonstrates that the clamps can be installed without impacting previously evaluated conditions in the UFSAR, and their installation has no impact on the bases of the Technical Specification and does not involve any unreviewed safety question.

II. DETERMINATION

1. Does the activity involve a Technical Specifications change or other Facility Operating License amendment?

   No. The clamp repairs ensure the integrity of each core spray downcomer inside the RPV. There is no unacceptable effect to any ECCS system. Current Technical Specifications (CTS) 3.5.A.1.b require an operable flowpath of taking suction from the suppression pool and transfering the water to the spray sparger in the RPV. The leakage assumed with the various 360° through-wall cracks in the downcomers does not render the flowpath

inoperable, since the core spray pumps are still capable of delivering design basis flow. Therefore, a change to the existing Technical Specifications or Improved Technical Specification is not required. Technical Specification sections 1.1, 2.1, 3.2, 3/4.5.A, 3/4.5.C, 3/4.5.D, 3/4.5.E and 3/4.5.F and Improved Technical Specifications section 3.5.1 were reviewed in making this determination.

2. Does the activity make changes to the facility as described in the SAR?

Yes. Although installation of the repair clamps does not involve a change in the manner in which the core spray line responds to design basis loadings, and the repairs evaluated under this 50.59 are not discussed in the SAR, the estimated leakage from the Core Spray piping in the vessel exceeds the original design allowable for the "B" loop. Therefore, installation of the clamp repair constitutes a change to the facility as described in the SAR.

The function of the modification is to ensure the structural integrity of the CS downcomer even if the reported defects were to grow to the full circumference of the weld #1 heat affected zone of the sleeve. The modification will also ensures the structural integrity of the 'D' downcomer in the event additional cracking (full circumferential) develops at weld locations 2 through 4 of Figure 1. The repair clamps the area where the core spray downcomer and the core spray sparger inlet pipe join. The repairs are shown conceptually in Figures 2 and 3. The upper clamp mechanically grips the downcomer, and bears on the top of the sleeve that attaches the downcomer to the core spray sparger inlet pipe. A rod is used to support and locate the lower clamp from the upper. The lower clamp is centered over the inlet pipe to inlet elbow weld joint. A U-bolt that attaches to the upper clamp provides axial restraint between the downcomer joint collar and the riser elbow, spanning the crack location(s). No other modification to the CS piping will be required.

The maximum leakage evaluated for the 'B' loop of core spray (343 GPM) exceeds the original design allowable of 100 GPM. However, the leakage margin evaluation is well with in margins established by the SAFER/GESTR-LOCA analysis. The maximum leakage evaluated for the 'A' loop is 78 GPM which is within the original design margins.

UFSAR Sections 3.0, 6.0, 6.5 and 14.6 were reviewed in making this determination.

3. Does the activity make changes to procedures as described in the SAR?

   No. The modification does not change any reactor or system operation, does not involve any new mode of operation, and does not involve any change to sequence of events. Therefore, the review of the UFSAR Sections 3.0, 6.0, 6.5 and 14.6 determined that the modification will not require a change to a procedure in the UFSAR.

4. Does the activity involve tests or experiments not described in the SAR?

   No. The modification involves the installation of clamp hardware on the core spray downcomer. No tests or experiments are required to validate the clamp design. Therefore, the review of the UFSAR Sections 3.0, 6.0, 6.5 and 14.6 determined that the modification will not require a change to the UFSAR.

Since the answer to question 2 is 'Yes', a safety evaluation is required.

III. SAFETY EVALUATION

A. Those accidents potentially negatively impacted by this change include:

   1. ECCS-LOCA,
   2. UFSAR Chapter 14 Transients
   3. LOCA-Radiological,
   4. Main Steamline Break (MSLB)
   5. Earthquake.

   In all cases, installing the core spray downcomer clamps has no or negligible effect on these plant safety analyses.

   1. May the possibility of occurrence of an accident previously evaluated in the SAR be increased?

      No. Plant systems and components will be capable of performing their intended functions with the clamps installed. The possibility of occurrence of an accident previously identified in UFSAR Section 14.6 is not increased. Clamp installations will not adversely affect any Code requirements imposed on the core spray system. The possibility of component failure is not increased. If the cracks propagate to 360

degrees, the separate portions of the downcomer are captured and thus there will be no possibility of loose parts resulting from the failure. The modification design incorporates provisions (i.e. crimping assembly bolts) to ensure the clamp hardware does not come loose and thus preventing any loose parts concerns.

2. May the consequences of an accident previously evaluated in the SAR be increased?

No. Systems and components used to mitigate the (radiological) consequences of the accidents in the UFSAR are not degraded by this modification. All of the events in the Peach Bottom UFSAR were examined to determine if the consequences of any of these events is increased by the installation of the repair clamps. Consequences (i.e., radiological dose) associated with the design basis accidents are evaluated in the UFSAR. The existing core spray downcomer and repair clamps do not function to mitigate the consequences of any UFSAR event except the design basis LOCA event. No UFSAR dose calculation will be impacted by this change. For the design basis LOCA event discussed in the UFSAR, the core spray line and downcomer provide the flow path inside the RPV for the ECCS flow to the core spray spargers. Maintaining this flow path is required to ensure that core cooling capability is maintained following the design basis LOCA. This repair design, through its restraint of the joint, ensures the integrity of the core spray downcomer, with a 360 degree through wall crack in the pipe sleeve, under DBA conditions. The modification will also ensure the structural integrity of the 'D' downcomer in the event additional full circumferential cracking develops at weld locations 2 through 4 of Figure 1.

An assessment of the leakage through the crack in the downcomer coupling sleeve was performed to confirm that this leakage has no significant effect on the existing ECCS analyses. The cumulative leakage for the "A" and "B" core spray loops following clamp installation are 78 GPM and 343 GPM respectively. The greater leakage value for the 'B' loop is based on addition circumferential cracks may be allowed at the downcomer/sparger inlet pipe joint with the 'D' downcomer clamp installed. These leakage rates are within the margins allowed for the core spray injection under the SAFER/GESTR-LOCA analysis.

The SAFER/GESTR-LOCA analysis demonstrated that 5,000 GPM @ 105 psig (with an associated run out flow of 6,250 GPM @ 0 psig) of

core spray flow is sufficient to maintain adequate core cooling. Existing system requirements maintain a pump supply flow of 6,250 GPM @ 105 psig with an associated runout flow of 7,825 GPM at 0 psig per loop. Therefore, the estimated cumulative leakage for each loop remains within the established margins for ECCS-LOCA requirements.

Variations in piping stresses associated with the additional weight of the repair hardware and with multiple downcomer cracking has been evaluated in references 1 and 2, and found acceptable.

Radiological consequences of the previously identified accidents are not increased. Therefore, it is concluded that the repair clamp installations ensure that the consequences of a design basis LOCA will not be increased.

The repair clamps impose a negligible change to the plant operating conditions, and thus, the ECCS-LOCA and transient analysis remain valid.

3. May the possibility of an accident of a different type than any previously evaluated in the SAR be created?

   No. The clamps are designed to the structural criteria specified in the UFSAR. All of the loads and load combinations specified in the SAR relevant to the core spray line have been evaluated and are within design allowables. The clamps do not add any new operational/failure mode or create any new challenge to safety related equipment or other equipment whose failure could cause a new type of accident.

B. The components important to safety which are impacted by the modification are the core spray system and RPV internals.

1. May the probability of occurrence of a malfunction of equipment "Important to Safety" previously evaluated in the SAR be increased?

   No. The clamp is designed and constructed as a safety related component. No adverse equipment interactions will be created by installing the clamps. Therefore, the probability of an equipment malfunction is not increased.

The design of the modification assumes the present cracks will grow to 360 degrees through wall. The modification will also ensure the structural integrity of the 'D' downcomer in the event additional full circumferential cracking develops at weld locations 2 through 4 of Figure 1. The installation of the downcomer repairs will limit the separation between the downcomer and inlet pipe to 0.054 inch. This maximum separation results from the temporary cooling of the CS riser relative to the newly installed U-bolt. It is conservatively assumed that the U-bolt is still at 550 degrees F when the downcomer is cooled to 310 degrees F, average temperature, by the injected water from the torus (240 degree F temperature difference). After a few minutes of post LOCA core spray system injection, the riser pipe and U-bolt temperatures will be in equilibrium. However, due to postulated displacement of a loose spool piece of pipe in the multiple crack scenario ('D' downcomer), the total width of the cracks will remain at .054 inch. For the 'A', 'B' and 'C' downcomers, the crack width will close to approximately .005 inch.

Analysis performed under reference 2 have confirmed that installation of the clamps does not impact previous repairs performed on the 120° and 240° azimuth T-Boxes.

2. May the consequences of a malfunction of equipment "Important to Safety" previously evaluated in the SAR be increased?

   No. The installation of the clamps ensures that each core spray line, even if cracked, will perform its safety function to ensure adequate core cooling (protect the fuel) by limiting separation between the downcomer and sparger inlet pipe. The clamps perform a passive function that does not interfere with any equipment that is used to mitigate any abnormal operating occurrence or the radiological consequences of a malfunction described in the UFSAR. Thus, the consequences of a malfunction of equipment important to safety is not increased.

   The cumulative leakage from each core spray loop will not prohibit the loops from providing adequate core cooling during a design basis LOCA. The cumulative leakage values of 78 GPM for loop "A" and 343 GPM for loop "B" are within the 1250 GPM flow margin established for each core spray loop in the SAFER/GESTR-LOCA analysis.

3. May the possibility of a different type of malfunction of equipment

"Important to Safety" other than any previously evaluated in the SAR be created?

No. All equipment assumed to operate in the transient analysis, and the safety related structures, systems and components will not be adversely affected by the clamps. All components interacting with the clamps will perform their intended functions of ensuring adequate core cooling to protect the fuel. The clamps do not increase challenges to or create any new challenge to equipment. The clamp does not create any new sequence of events that lead to a new type of malfunction. Therefore, the possibility of a different type of component malfunction than evaluated in the UFSAR is not created.

C. List the Technical Specifications Bases reviewed for potential reduction in the margin of safety.

The applicable Technical Specification Bases reviewed were 1.1, 2.1, 3.0, 3.5.A, 3.5.B, 3.5.C, 3.5.D, 3.5.E and 3.5.F, and Improved Technical Specifications bases 3.5. These bases do not contain any margin of safety that is affected by Modification P00335.

1. Is the margin of safety as defined in the Bases of any Technical Specification reduced?

No. The Technical Specifications and their Bases are not affected by the installation of the clamps. No safety analysis referenced in a Bases will change. Therefore, the installation of the clamps will not affect the margin of safety of any Technical Specification Bases.

D. **CONCLUSION**

This evaluation has investigated the installation of clamps on the core spray lines at PBAPS. The plant licensing bases have been reviewed. This review demonstrates that clamps can be installed (1) without an increase in the probability or consequences of an accident or malfunction previously evaluated, (2) without creating the possibility of an accident or malfunction of a new or different kind from any previously evaluated and (3) and without reducing the margin of safety in the bases of a Technical Specification. Therefore, installation of the core spray line clamps does

not involve any unreviewed safety question.

IV. REFERENCES

1. GENE-771-99-0295, Rev.2, Dated October, 1995, Core Spray Line Downcomer Bracket Stress Assessment Report.

2. GENE -771-98-0295, Rev 2, Dated October 1995, Core Spray Line Seismic Assessment Report

IV. APPROVALS

Prepared by: Michael R Delaney Date: 10/8/95
PECO, PB Design Engineering

Prepared by: ______________ Date ________
General Electric Nuclear Energy

Interface Review: ______________ Date: 10/08/95
PECO, PB Design Engineering

Interface Review: ______________ Date: 10/8/95
PECO, PB Component Engineering

Peer Review: ______________ Date: 10/8/95
PECO, Nuclear Engineering Division

Approval: Vijay M. Nilekani Date: 10/08/95
PECO, Nuclear Engineering Division

IV. APPROVALS

Prepared by: Michael R Delawery — PECO, PB Design Engineering — Date: 10/8/95

Prepared by: W L Rauman — General Electric Nuclear Energy — Date 10/8/95

Interface Review: ____________ PECO, PB Design Engineering — Date: ______

Interface Review: ____________ PECO, PB Component Engineering — Date: 10/8/95

Peer Review: ____________ PECO, Nuclear Engineering Division — Date: 10/8/95

Approval: ____________ PECO, Nuclear Engineering Division — Date: ______

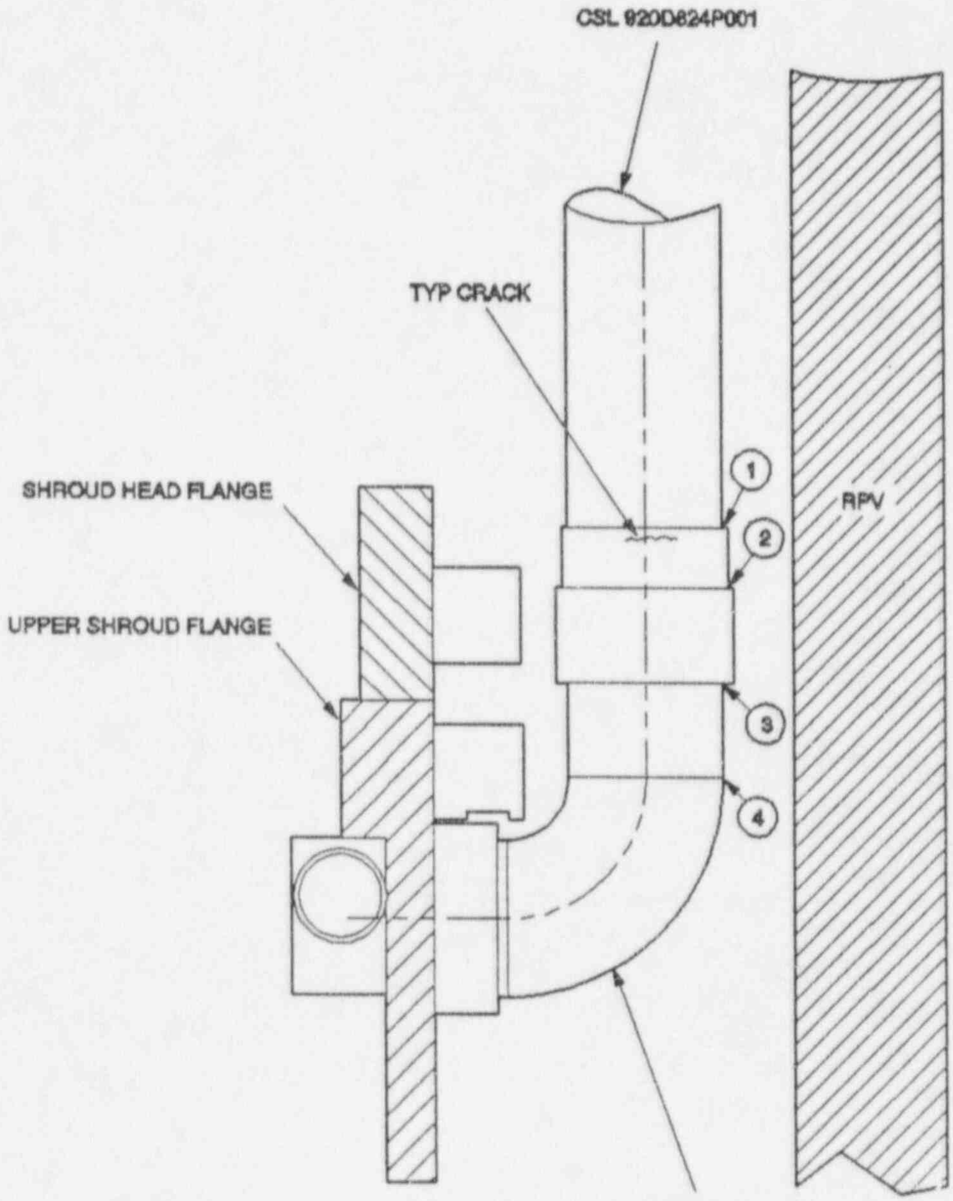


Figure 1. Core Spray Sparger Riser/Downcomer

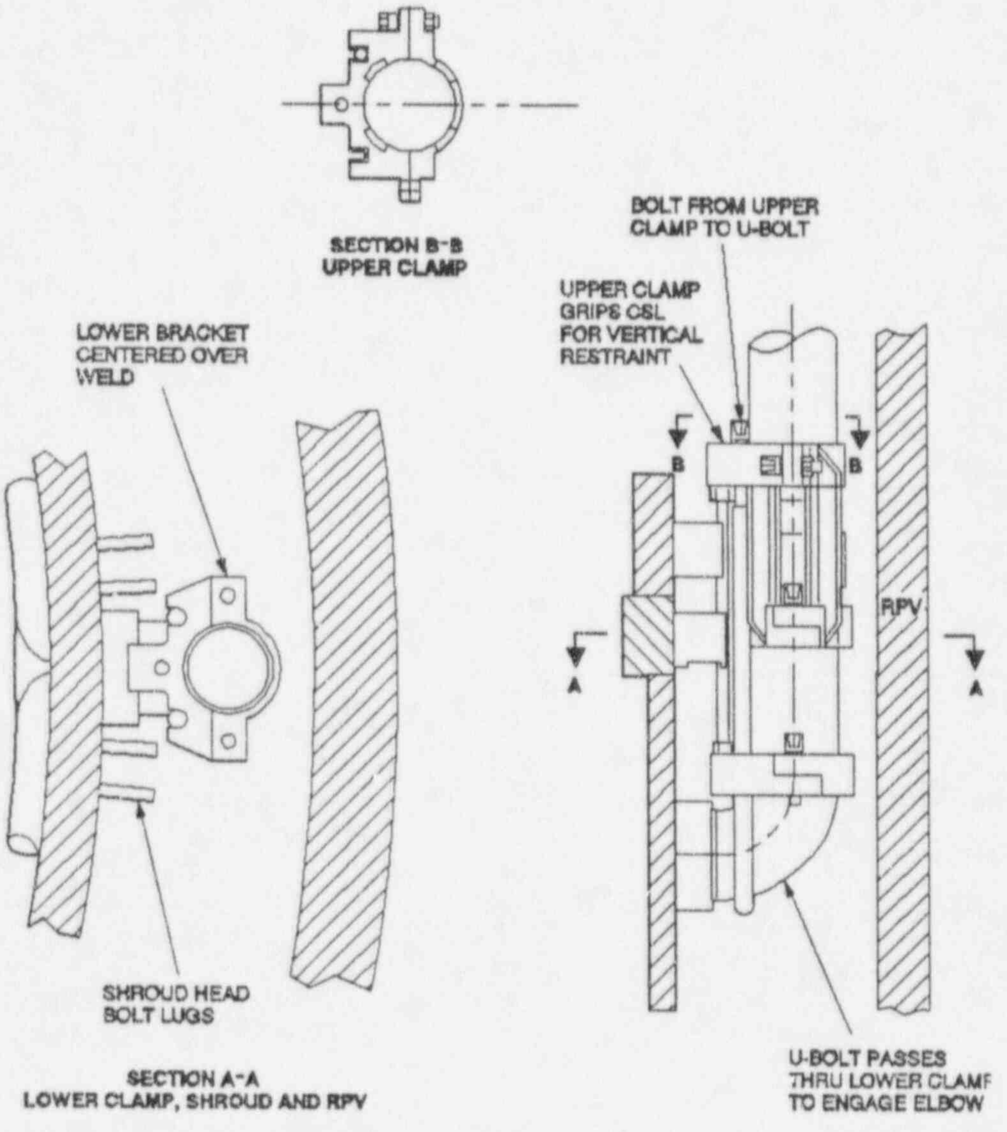


Figure 2. CSS Riser Repair Concept

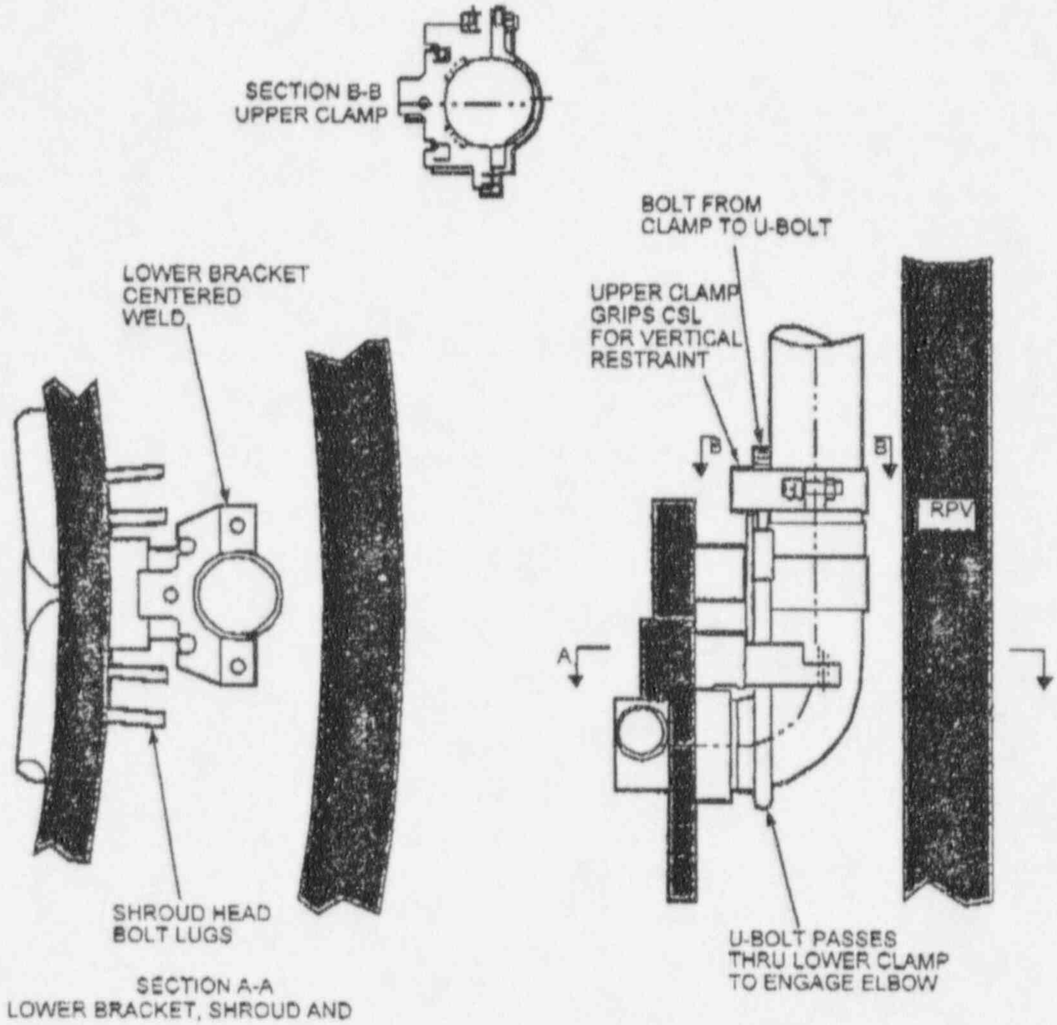


Figure 3. CSS Riser Repair Concept

GENE-771-99-0295, REV.2
DRF B11-00642
SHEET 1

CORE SPRAY LINE DOWNCOMER BRACKET STRESS ASSESSMENT REPORT for PEACH BOTTOM ATOMIC POWER STATION, UNIT 3

Modification P00335

Prepared by: 10/9/95
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Approved by: 10/9/95
F.C. Gaylord, Project Manager

| 10/9/95

APPENDIX A - MAXIMUM STRESS SUMMARY

U-Bolt Stresses

Service Level	Calculated Stress Intensity (ksi)	Allowable Stress (ksi)
Normal/Upset (Primary Membrane)	2.5	Sm = 29.5
Normal/Upset (Primary Membrane + Primary Bending)	5.37	1.5Sm = 44.2
Normal/Upset (Secondary)	2.5	3Sm = 88.4
Service Level C - Pm Pm + Pb	2.5 5.37	1.5Sm = 44.2 2.25Sm = 66.4
Service Level D Pm / Pm + Pb	2.5/5.37	Sy = 32.7/.7Su = 62.9
Max. Cumulative Usage	0.0	1.0

Fastener Stresses

Service Level	Category	Calculated Stress Intensity (ksi)	Allowable Stress (ksi)
Normal/Upset (Primary Membrane + Secondary Membrane including Preload)	Shank or Threads Thread Shear Bearing	22.37 6.43 7.66	.9Sy = 29.4 .6Sy = 19.6 2.7Sy = 41.72
Normal/Upset (Primary Membrane and Bending + Secondary Membrane and Bending)	Shank or Threads	22.37	1.2Sy = 39.2
Service Level C - Primary Membrane	U-bolt-elbow contact	22.37	1.5Sm = 44.2
Service Level C - Primary Membrane + Primary Bending		22.37	2.25Sm = 66.4
Service Level D Pm		22.37	Sy = 32.7
Max. Cumulative Usage		.001	1.0

10/9/95

1. INTRODUCTION

1. Background

1.1 Core Spray Sparger Downcomer Welds. Each CSS (upper and lower) includes two 6 NPS schedule 40 inlet pipes which penetrate the shroud. An elbow and vertical pipe spool are connected to these inlet pipes outside the shroud; the assembly of this elbow and the vertical pipe spool will be referred to as the CSS downcomer. The core spray lines (CSL) connect to the CSS downcomer pipes at the approximate elevation of the top of the shroud. The field welded connections between the CSL downcomer and the CSS downcomer pipe is shown at zone B-16, sheet 1 on reactor assembly drawing 2.1.f. The semi-circular CSL is a 304 stainless steel piping run internal to the reactor. Its purpose is to carry the core spray system flow from the core spray nozzle thermal sleeve (located at 472 inches elevation above vessel zero, N5A at 120°, N5B at 240°, see 2.1.a and 2.1.f) to two of the CSS downcomers. The 6-inch CSL laterals are welded to an 7.93 inch outside diameter T-box as shown on 2.1.d. The CSL T-box connection with the core spray nozzle thermal sleeve is a reactor assembly weld as shown on sheet 1, zone B-15. Each horizontal section of the CSL is supported from the vessel wall by a CSL bracket (158B8353P001) which is welded to the vessel 20 inches from the nozzle. and a CSL clamp (see 136B1908P001 and sheet 4 of 2.1.a), located at 15°, 165°, 195°, and 345°.

1.2 CSS Downcomer Modification. During the Peach Bottom Unit 3 1993 refueling outage and inspections done in response to IE Bulletin 80-13, circumferential IGSCC defects were found on one of the CSS downcomer connections at 172.5°, adjacent to the upper horizontal weld to the vertical downcomer pipe, see Figure 3-1. In the 1995 refueling outage, cracks were also found in the 7.5 deg., 187.5 deg. and 352.5 deg. downcomer pipes. The cracks vary in length from a minimum of 7.5 inches to 17.5 inches are in the weld heat affected zone base material, on the connector sleeve, about 1/4 inch from the weld. A repair (by modification) is designed that addresses the identified cracking in the heat affected zone in the pipe sleeve of the downcomer sleeve/spigot joint, including potential additional cracking in the spigot/sleeve and elbow area for the 172.5 deg. azimuth downcomer.

1.3 Modification Repair. The modification repair of the CSS downcomer (172.5 deg.) includes an external clamp assembly which will be mechanically attached to the CSS downcomer at the defect area. The clamp is placed on the CSL downcomer above the junction with the CSS downcomer pipe and extends below the connector, as shown in Figure 1. A lower clamp is placed at the location of the pipe to lower elbow weld. This clamp encircles 360 degrees degrees of the weld.

The upper clamp is joined by a U-bolt to the elbow to provide vertical structural continuity across the defect area. For the 7.5 deg., 187.5 deg. and 352.5 deg. azimuths, a similar simplified modification repair is used. This repair employes an upper clamp without the extension below the connector and a half clamp at the lower weld. The remainder of the repair is identical to the 172.5 deg. clamp.

1.2 Purpose

This report transmits the results of the design stress analysis which assesses the effects of the core spray system operational cycles and shroud stabilizer effects on the modification hardware. Also included are the results of a core spray system leakage analysis. The analysis is contained in Design Record File (DRF) B11-00642.

2. SUMMARY AND CONCLUSIONS

2.1 Scope

This report covers only the modification hardware and localized stresses, if any, imposed on the core spray line. For the purposes of this analysis, the structural integrity at weld locations other than the crack location is considered to be complete. At the crack location, crack propagation to 360 degrees is considered for both stress and leakage evaluation.

2.2 ASME III Code Compliance's

The clamp stresses satisfy the requirements of the ASME Code, Section III, Sub-section NG. A summary of the results obtained by solution of Sub-section NG equations for all significant locations is contained in Appendix A of the stress analysis located in DRF B11-00642 for both clamp designs and contained herein as Appendix A. The stresses reported herein are the maxima for each classification.

The U-Bolt section stresses are evaluated to the requirements of paragraph NG3222 for both repair designs. The preload imposed on the U-bolt at installation is greater than the cyclical loadings and as a result, the maximum usage factor for the U-bolt is 0. The maximum primary plus bending stress is 5,370 psi compared to an allowable stress of 44175 psi and occurs in the curved section of the bolt.

Threaded fastener stresses are evaluated to the requirements of paragraph NG3232. The maximum primary membrane plus secondary membrane including preload is 22,370 psi compared to an allowable of 29,400 psi and occurrs in the cross sectional area of the 1 inch bolt. The preload imposed on the bolting

exceeds the cyclical loadings and as a result, the fastener maximum fatigue usage is .001.

Although the LOCA event is considered a Service Level C condition. Service Level A and B allowables are easily met for all load conditions as shown in the Appendix.

Evaluation of possible leakage is based on the assumption that the identified crack propagates to 360 degrees with another potential crack existing also for 360 degrees within the connector region for the 172.5 degree location. Upon the activation of the core spray system, the core spray line is assumed to contract to the extent that a total .054 inch crack width will be present. Due to possible mis-alignment of the isolated pipe segment preventing crack closure upon temperature equilibrium, the gap is assumed to remain constant. At the remaining downcomer locations, the cracks are assumed to be no larger than .005 inch. The normal system leakage through the CSL vent when added to the connector region crack leakage amounts to 343 gpm for the "A" loop and 78 GPM for the "B" loop in the steady state condition.

APPENDIX A cont'd.

Upper Clamp Stresses(172.5 degrees)

Service Level	Calculated Stress Intensity (ksi)	Allowable Stress (ksi)
Normal/Upset (Primary Membrane)	2.2	Sm = 17.5
Normal/Upset (Primary Membrane + Primary Bending)	2.9	1.5Sm = 26.25
Normal/Upset (Secondary)	42.8	3Sm = 52.5
Service Level C - Pm Pm + Pb	2.4 3.1	1.5Sm = 26.25 2.25Sm = 39.37
Service Level D Pm / Pm + Pb	4.7/5.8	Sy = 30/.7Su = 75
Max. Cumulative Usage	.31	1.0

Flowrates

System Operation	Flowrate (gpm) w/leakage (based on 6250 GPM Design Flow)	Required Flowrate (gpm)
LOCA	5907	5000

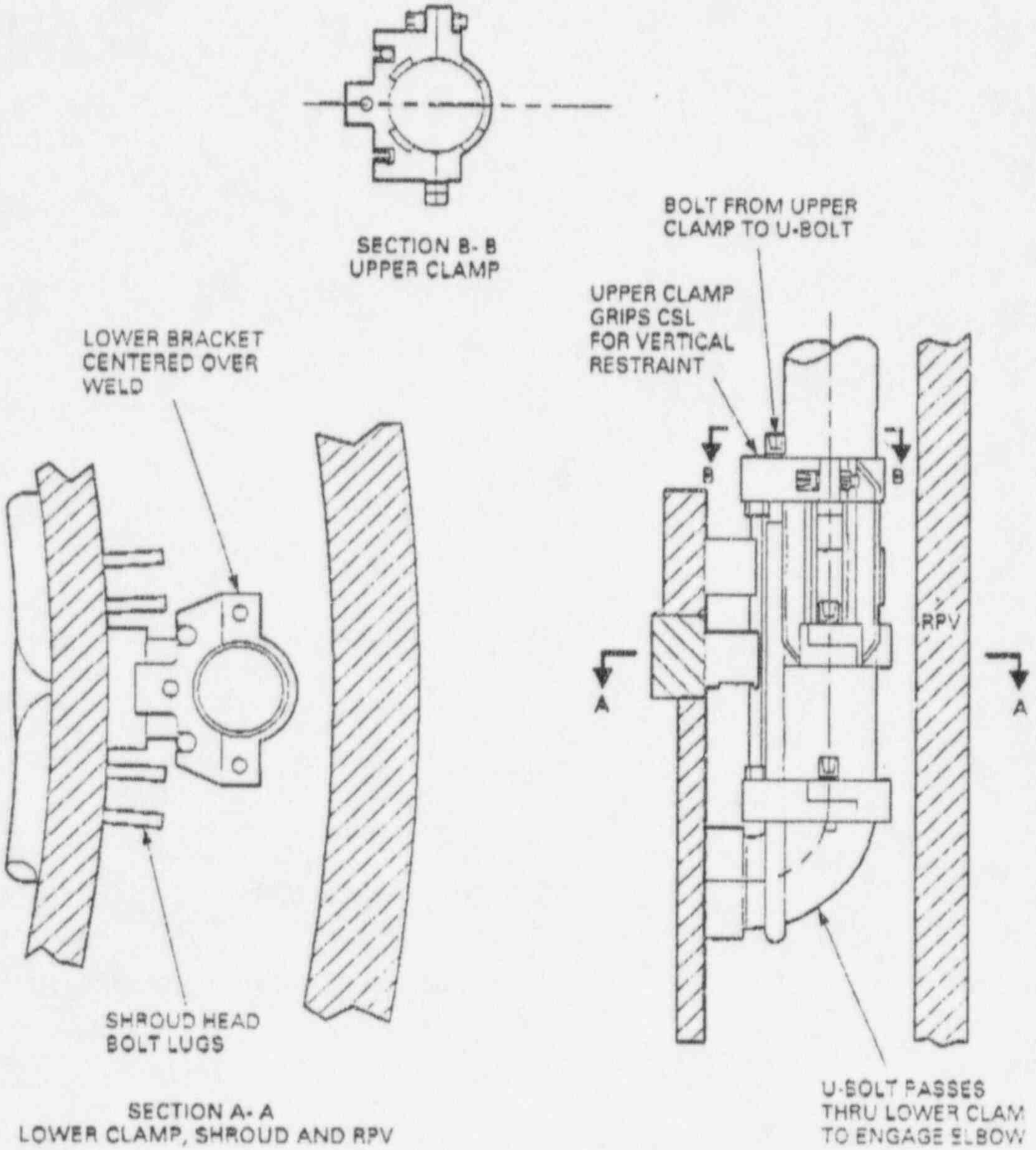

Figure 1. CSS Riser Repair Concept

GENE-771-98-0295, REV.2
DRF B11-00642
SHEET 1

CORE SPRAY LINE SEISMIC ASSESSMENT REPORT
for
PEACH BOTTOM ATOMIC POWER STATION, UNIT 3

Modification P00335

Prepared by: H L Hwang 10/6/95
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K K Fujikawa Senior Engineer 10/9/95

Approved by: 10/9/95
F.C. Gaylord Project Manager

1.0 INTRODUCTION

1.1 Background

Peach Bottom Atomic Power Station Unit 3 has two Core Spray Lines (CSL) which enter the reactor pressure vessel (RPV) at the 120 degree and 240 degree azimuth locations. A set of two 316L Stainless Steel (SS) reinforcement brackets were previously added to connect the T-box to the CSL pipes to prevent pipe separation from the T-box. This connection is made by applying fillet welds on both sides of the brackets. In addition, the CSL joint near the shroud penetration is assumed to be cracked (as discussed in the assumptions below), the bracket (Modification P00335) shall be added to the 7.5, 172.5, 187.5 and 352.5 degree CSL downcomer (4 locations total) to provide reinforcement at the location of the downcomer weld joint connection. This modification is a bolted design utilizing clamps which attach to the CSL.

1.2 Purpose

This report transmits the results of the design stress analysis which assesses the effects of the new brackets (Modification P00335) on the existing modified CSL and brackets. The purpose of the analysis is to demonstrate the seismic structural adequacy of the CSL and reinforcement brackets at Peach Bottom Unit 3. The analysis is contained in Design Record Files (DRF) B13-01732 and B11-00642.

This revision incorporates the relative seismic displacement (design earthquake) at the shroud penetration to be 0.400 inches. The total number of equivalent cycles is 50 cycles.

2.0 ASSUMPTIONS

The following assumptions were used in the CSL structural analysis:

1. The CSL downcomer sleeve/spigot assembly near the shroud penetration is assumed to have a 360° through wall crack. No credit is taken for any remaining ligament at the postulated crack location.

2. The connection at the four repair joints, which includes the CSL downcomer sleeve/spigot assembly and the repair bracket, is assumed to have a moment carrying capability equivalent to 10% of the original moment of inertia for an eight inch length of the core spray pipe above the short radius elbow near the shroud.

gjs MLB

3. Fifty stress cycles is assumed for the seismic event.

4. Displacements associated with the core shroud stabilizers installed are utilized.

5. The fatigue usage includes the thermal effects due to both the uncracked and cracked CSL configurations. This is conservative because, the thermal case is counted twice in the fatigue analysis, plus the thermal stresses for the uncracked configuration are much less than the stresses for the cracked configuration.

6. The CSL is analyzed consistent with the requirements of Class 1 pipe per ASME III Subsection NB-3600. This includes the stress indices per NB-3600.

3.0 MODEL DESCRIPTION

A finite element model of the CSL was created which included the CSL pipe from the thermal sleeve at the RPV nozzle to the CSL supports near the shroud penetration. The model includes the reinforcement bracket at the T-box connection and the elbows to the penetration sleeve, but excludes the penetration sleeve. The joint at the U-bolt clamps were approximated by assuming the moment of inertia at lower pipe element to 10% of the original moment of inertia.

Figure 1A shows a sketch of the model. Beam elements were used for the CSL pipe, thin shell elements were used to model the T-box, reinforcement brackets at the T-box and a portion of the pipe near the T-box. Boundary elements were used to simulate the CSL pipe supports.

4.0 LOAD CASES

Thirteen different cases were analyzed and are listed in Table 1.

5.0 SUMMARY AND CONCLUSIONS

5.1 ASME III Code Compliance

The brackets and the piping attachment stresses are analyzed according to NB-3200 requirements. The results are tabulated in Appendix A-1 and A-2. The T-box had the maximum stresses which are briefly summarized as follows. The maximum fatigue usage factor is 0.324. This is at the T-box bracket fillet weld to the pipe. The main contribution to the fatigue usage is due to combination of OBEI and OBED. The maximum primary stress is the Service Level B condition. The primary-membrane-stress-plus-primary-bending-stress is 21,100 psi. The stress is within the allowable limit of 25,500 psi. The maximum stress for Service Level D is 38,500 psi (maximum local stress)as compared to 3 Sm=51,000 psi. The analysis also assumes SSE is twice OBE, which is conservative. A conservative stress

concentration value of 4.0, which includes a 1.2 factor for bending components and 3.33 for peak stresses is used for the fatigue analysis.

In the analysis it was assumed that there are 50 cycles with total separation between T-box and core spray pipes.

This analysis simulates the cracked condition equivalent to 10% moment of inertia exist for 8 inches length of the core spray pipe above the short elbow near the shroud.

The CSL pipe stresses satisfy the requirements of Article NB-3600 of ASME Section III. A summary of the results obtained by the solution of Subarticle NB-3650 equations for all significant joints in the piping system is contained in Appendix D of the analysis located in the referenced DRF's, and contained herein as Appendix A-3. The maximum primary stress ratio is the primary membrane stress for the Service Level B condition. The stress value for Service Level B is 5,952 psi as compared to the allowable stress of 25,500 psi. The maximum thermal expansion stress (Equation 12) for pipe element per NB-3600 is 20,902 psi with a stress ratio of 0.41. The maximum Equation 13 stress is 5,486 psi. The maximum fatigue usage factor is 0.001. The piping model at the sleeve crack causes moment relief at the joints. The analysis model assumes that 10% moment of inertia at the sleeve is existing. This assumption is considered reasonable because the both of OBED and OBEI can cause loads on the elbows and the T-box brackets.

5.2 Conclusions

The results of the stress analysis shows that the core spray line with the repair brackets is structurally adequate to withstand the operating load conditions.

Table 1. Analysis Cases

RUN #	Load Types	Case	Condition	T-box both ends separation
1	Thermal	1	Normal	NO
2	Thermal	2	Normal	YES
3	Weight	1	Normal	YES
4	OBEIX	1	Static g	YES
5	OBEIY	2	Static g	YES
6	OBEIZ	3	Static g	YES
7	OBED-X	1	Static	YES
8	OBED-Z	3	Static	YES
9	LOCA Y DISP	1	Static	YES
10	OBED-X	1	Static	NO
11	OBED-Z	3	Static	NO
12	OBEI-X	1	Response spectrum	YES
13	OBEI-Z	3	Response spectrum	YES

Note : All cases assume the CSL ~~pipe~~ is cracked at the bolted clamp locations.

DOWNCOMER SLEEVE/SPIGOT ASSEMBLY.

APPENDIX A - STRESS SUMMARY

A-1: T-box Bracket Stresses per NB-3200

Service Level	Calculated Stress Intensity (ksi)	Allowable Stress (ksi)
Normal/Upset (Primary)	21.1	1.5Sm = 25.5
Normal/Upset (Primary + Sec. excluding thermal bending)	35.7	3.0Sm = 51.0
Normal/Upset (Primary + Secondary)	64.6	N/A
Service Level C	21.1	2.25Sm = 38.25
Service Level D	38.5	3.0Sm = 51.0
Max. Cumulative Usage	0.324	1.0

A-2: Pipe Elements to T-box Bracket per NB-3200

Service Level	Calculated Stress Intensity (ksi)	Allowable Stress (ksi)
Normal/Upset (Primary)	17.5*	1.5Sm = 25.5
Normal/Upset (Primary + Sec. excluding thermal bending)	25.5	3.0Sm = 51.0
Normal/Upset (Primary + Secondary)	35.0	N/A
Service Level C	17.5	2.25Sm = 38.25
Service Level D	23.0	3.0Sm = 51.0
Max. Cumulative Usage	0.021	1.0

*Element local stress -- the average stress across the section is 15.1 ksi<25.5 ksi.

A-3: Pipe, Elbows and Components per NB-3600

Service Level	Calculated Stress Intensity (ksi)	Allowable Stress (ksi)
Normal/Upset (Primary)	6.0	1.5Sm = 25.5
Normal/Upset (Primary + Sec. excluding thermal bending)	5.5	3.0Sm = 51.0
Normal/Upset (Primary + Secondary)	63.1	N/A
Service Level C	6.0	2.25Sm = 38.25
Service Level D	12.0	3.0Sm = 51.0
Max. Cumulative Usage	0.001	1.0
Thermal Exp. (Eq. 12)	20.9	3.0Sm = 51.0

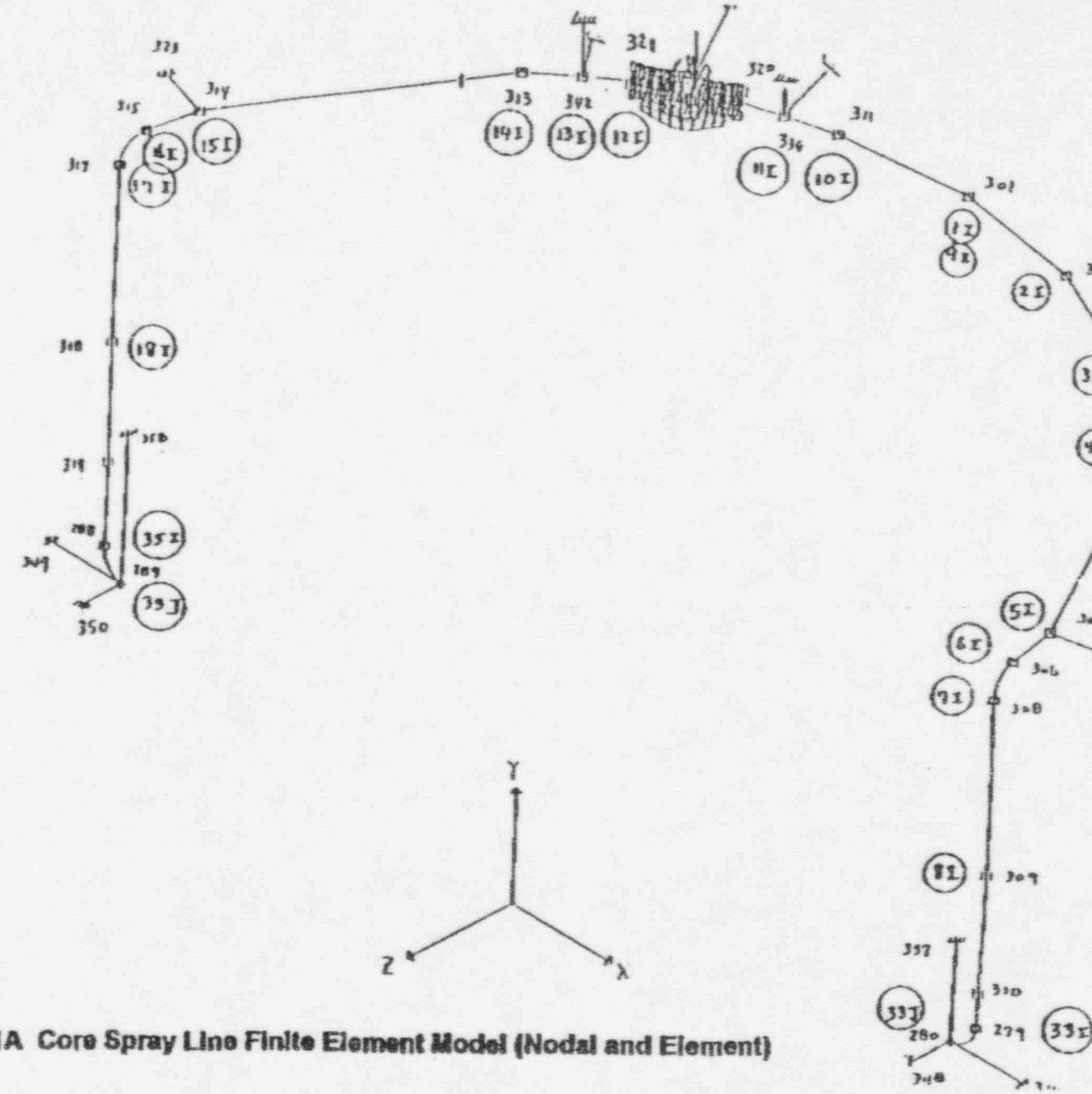

Figure 1A Core Spray Line Finite Element Model (Nodal and Element)

ATTACHMENT 2

ADDITIONAL INFORMATION IN
SUPPORT OF NRC'S REVIEW OF
PECO ENERGY'S REQUEST TO RESUME
OPERATION

Question #1

Provide the development of the loads during normal operation and postulated accident conditions that were used to establish the structural integrity of the Core Spray Line (CSL) clamp design at Peach Bottom Atomic Power Station (PBAPS) Unit 3.

Response

The loads applied to the finite element model (FEM) were obtained from the analysis of the core spray pipe. The core spray model is provided in Figure 1A of GENE-771-98-0295, Rev. 2. The CSL was modeled in conjunction with the core spray nozzle thermal sleeve, the T-box, and the reinforcement bracket to the pipe support joint just before the shroud penetration location.

The analysis included the cases as (1) design condition (no crack) and (2) with full separation of the CSL and T-box. To simulate the separation condition, all the plate elements, 360 degree circumference, between the T-box and the core spray pipe, before the weld of the bracket, are assigned with negligible Young modulus. The model has also considered that the downcomer has cracked and is tied together by a link at the location of the clamp modification. The force can be transferred through the joint, but the moment is released. Weight of the linkage (300lb) was included in the analysis model.

The Engineering Computer Program SAP4G07 was used to calculate the affect of the piping system due to thermal expansion, weight and seismic loads.

Thirteen load cases are analyzed. The analysis cases are summarized in Table 1 of GENE-771-98-0295, Rev 2. Description of each analysis case are in the following paragraphs.

THERMAL CASES

The first case assumes the core spray pipes are connected to the T-box as the original design condition. This is normal operating condition in which the Reactor Pressure Vessel (RPV) expands radially with carbon steel expansion coefficient and the core spray line expands with stainless steel expansion coefficient. The second case is the same as Thermal Case 1 except full separation of T-box and CSL pipe is assumed.

WEIGHT ANALYSIS

Weight analysis as applied to normal operating conditions has been performed. Full pipe separations at the T-box is assumed to calculate the maximum loads on the brackets.

SEISMIC LOADS BY STATIC ANALYSIS

Seismic loads acting on the piping system are caused by the response of the reactor building structure and reactor pressure vessel. The seismic loads are defined as the static seismic coefficients. The Safety Shutdown Earthquake (SSE) accelerations, 1.25g and 0.3 g for the horizontal and vertical SSE loads, are calculated to compare with the results from response spectrum analysis. The greater values are used in the load calculations.

SEISMIC ANCHOR DISPLACEMENTS

Static analyses are performed for the relative displacements between the shroud penetration movement and the CSL nozzle due to Operational Base Earthquake (OBE) event, which is 1.2" in both E-W and N-S directions. This load is the major contribution to the fatigue usage factor of the pipe, the brackets, and the clamp. Run #7 and #8 assume that the T-box and core spray pipe are separated. Run #10 and #11 assumed no separation.

HYDRAULIC TRANSIENT LOADS

The hydraulic transient is shown in design specification, 25A5341, Sheet 5 of this specification, and specifies that the core spray flow is developed linearly in 20 seconds. The load in the piping system is very small. A hydraulic transient analysis was performed using 10 seconds instead of 20 seconds, which is conservative. The maximum pipe segment force amplitude is less than 20 lb. An example of pipe segment force time history is shown in Figure 1. The transient load is negligible for the piping analysis.

In the finite element of the downcomer clamp, the vertical distance form the horizontal centerline of the downcomer pipe at the shroud location to the free end of the pipe was made to coincide with the location of node 318 of element 18l of the piping analysis model. The forces and moments at node 318 were applied to the end of the vertical pipe of the FEM used in this analysis. Two load direction combinations were considered due to non-symmetry of the FEM about the x-axis: 1 (+)x and (+)y, and 2 (+)x and (-)y; the FEM is symmetric about the y-axis. The horizontal force in the x-direction (Fx) and the moment about the y-axis (My) were applied together, and the horizontal force in the y-direction (Fy) and the moment about the x-axis (Mx) were applied together. The absolute value of the magnitude of the forces and moments are provided below.

Load Type	Fx [kips]	Fy [kips]	Fz [kips]	Mx [in-kips]	My [in-kips]
Thermal	0.4	0.1	1.0	1.4	9.9
Weight	0	0	0.1	0.1	0.2
OBEL-X	0	0	0	0.7	0.3
OBEL-Z	0	0	0	0.1	0.5
OBED-X	0.3	0.8	0.4	20.3	7.1
OBED-Z	1.1	0.3	1.3	7.4	28.2
LOCA	0.6	0.1	0.9	1.7	14.6
SSEI-X	0	0	0	0.9	0.4
SSEI-Z	0	0	0	0.2	0.7
UNIT LOADS	1.0	1.0	1.0	10.0	10.0

It is noted that the load applied to the clamp design for OBED-X and OBED-Z are the maximum loads in the design. These loads are calculated based on the assumption that the relative displacements between the shroud to RPV nozzle is 1.20 inches. Later analysis of the shroud assuming partial crack was performed and the calculated relative displacements is reduced to 0.397 inches. This is only about one third of the forces and moments used in the calculation.

QUESTION #2

If some loads were considered negligible, provide the basis for the assumptions.

RESPONSE #2

The negligible loads were included in the previous response.

QUESTION #3

Provide the back-up stress calculations related to the threaded fasteners to demonstrate ASME code compliance.

RESPONSE #3

The threaded fastener design of the CSL clamp was performed using the ASME Code, Section NG as a guide. This design information was included in as part of the CSL Downcomer Bracket Stress Assessment Report, GENE-771-99-0295, Rev 2. Appendix A, to this Attachment, consists of the supporting calculations for the threaded fasteners design. The calculated stress intensity values included in the Stress Assessment Report have been highlighted in Appendix A.

QUESTION #4

Provide the basis for the assumed crack width upon activation of in core spray system.

RESPONSE #4

Upon activation of the Emergency Core Cooling System (ECCS), the hot riser pipe (304 material) is cooled to a temperature well below the initial high temperature of 550° F. However, the clamp hardware itself (U-bolt) is made of a different material, namely XM-19, with a lower coefficient of thermal expansion than that the 304 riser pipe. The clamp hardware remains at a temperature of 550° F during this event. Thus, the riser pipe between the base of the upper clamp and U-bolt restraint on the bottom elbow contracts relative to the clamp hardware between the same distance. This, in turn, causes the crack in the upper weld to open up. Thus, the amount of this initial crack opening is calculated based on the length over which the differential expansion acts during the event. The differential thermal movement described, applies to the clamp hardware on all four core spray line risers.

QUESTION #5

Provide justification for using a dual clamp design at one location and a single clamp design at the other three locations.

RESPONSE #5

The dual clamp design to be installed on the "D" downcomer was designed and fabricated prior to refueling outage 3R10 (fall 1995). The design repairs the crack indications identified in the Heat Affected Zone (HAZ) of the sleeve, below the pipe/sleeve weld. This design also provided for contingencies if any additional crack indications were identified in the "D" downcomer (or any other downcomer) during 3R10.

The single clamp design, to be installed on the "A", "B", and "C", downcomers, also repairs the crack indications identified in the HAZ of the sleeve, below the pipe/sleeve weld. This design was the original design for the "D" downcomer indication, developed prior to adding in additional contingencies. Fabrication and installation of the single clamp design is adequate to repair the downcomer indications found on "A", "B", and "C" downcomers. The contingencies are not needed because all cracks found on the "A", "B", "C", and "D" downcomers were in the same location. Use of the double clamp is not necessary, it is a much more conservative repair than needed, and is being used since it is available.

APPENDIX A
ATTACHMENT 2

BACK-UP STRESS
DATA FOR THE THREADED CONNECTORS

5.4 Bolt Dimensions and Loads

Applied Preloads

$$Preload_{clamp\_halves} = \frac{100 \cdot ft \cdot lbf}{(.20) \cdot (.75 \cdot in)} \qquad Preload_{Ubolt} = \frac{75 \cdot ft \cdot lbf}{(.20) \cdot (.75 \cdot in)}$$

$$Preload_{clamp\_halves} = 8000 \cdot lbf \qquad Preload_{Ubolt} = 6000 \cdot lbf$$

$$Preload_{connecting\_rod} = \frac{100 \cdot ft \cdot lbf}{(.20) \cdot (1.00 \cdot in)}$$

$$Preload_{connecting\_rod} = 6000 \cdot lbf$$

5.4.1 Thread Dimensions (Connecting Rod)

The thread dimensions for 1.00-12UNF are obtained from ANSI B1.1-1982.

$En\_max := .9535 \cdot in$ (maximum pitch diameter of internal thread)

$Ds\_min := .9868 \cdot in$ (minimum major diameter of external thread)

$Es\_min := .9382 \cdot in$ (minimum pitch diameter of external thread)

$Kn\_max := .928 \cdot in$ (maximum minor diameter of internal thread)

$dm := \frac{.8990 - 1.00}{2} \cdot in$ (Mean Diameter) $d := 1.00 \cdot in$ (Major Diameter)

$Le := 1.00 \cdot in$ $n := \frac{12}{in}$ (number of thread per inch) $l := \frac{1}{12} \cdot in$ (Lead)

(length of thread engagement)

The thread dimensions for 0.75-16UNF are obtained from ANSI B1.1-1982.

$En\_max := .7159 \cdot in$ (maximum pitch diameter of internal thread)

$Ds\_min := .7391 \cdot in$ (minimum major diameter of external thread)

$Es\_min := .7029 \cdot in$ (minimum pitch diameter of external thread)

$Kn\_max := .696 \cdot in$ (maximum minor diameter of internal thread)

$dm := \frac{.6740 - 0.75}{2} \cdot in$ (Mean Diameter) $d := 0.75 \cdot in$ (Major Diameter)

$Le := .75 \cdot in$ $n := \frac{16}{in}$ (number of thread per inch) $l := \frac{1}{16} \cdot in$ (Lead)

(length of thread engagement)

PARAGRAPH 5.5 NOT APPLICABLE
AK

5.6 Bolt/Nut Thread Stress Analysis

The thread shear area was calculated using the methodology and equations given in Appendix B, Paragraph B2 of Reference 13.

5.6.1 Internal Thread Shear Area (Nut)

$$ASn := \pi \cdot n \cdot Le \cdot Ds\_min \cdot \left[\frac{1}{2 \cdot n} - .57735 \cdot (Ds\_min - En\_max)\right] \qquad ASn = 1.244 \cdot in^2$$

5.6.2 Nut Thread Shear Stress

The applied bolt loads for all operating conditions are less than the applied preload. Therefore, the applied preload condition stresses bound all Normal, Upset, condition stresses.

5.6.2.1 Normal/Upset/Emergency Condition Nut Thread Shear Stress

$$\tau_{preload} = \frac{Preload_{clamp\_halves}}{ASn}$$

$$\tau_{preload} = 6431 \cdot psi$$

SAME LIMITS AS NG

$\tau\_Limit\_Level\_A\_B\_C := .6 \cdot Sy\_XM19$

(Reference 2, Paragraph NB 3232.1(b))

$\tau\_Limit\_Level\_A\_B\_C = 1.959 \cdot 10^4 \cdot psi$

5.6.3 External Thread Shear Area (Bolt)

$$ASs := \pi \cdot n \cdot Le \cdot Kn\_max \cdot \left[\frac{1}{2 \cdot n} + .57735 \cdot (Es\_min - Kn\_max)\right] \qquad ASs = 0.924 \cdot in^2$$

5.6.4 Bolt Thread Shear Stress

5.6.4.1 Normal/Upset/Emergency Condition Bolt Thread Shear Stress

$\tau\_Limit\_Level\_A\_B\_C := .6 \cdot Sy\_XM19$

$$\tau_{preload} = \frac{Preload_{clamp\_halves}}{ASs}$$

$$\tau_{preload} = 8653 \cdot psi \qquad \tau\_Limit\_Level\_A\_B\_C = 1.959 \cdot 10^4 \cdot psi$$

5.7 Bolt Section Property Calculations

5.7.1 .75 " Dia Bolt Shank Section

$$A_{shank} := \pi \cdot \left(\frac{.75}{2} \cdot in\right)^2$$

$$A_{shank} = 0.442 \cdot in^2$$

$$I_{shank} := \frac{\pi \cdot (.75 \cdot in)^4}{64}$$

$$I_{shank} = 0.016 \cdot in^4$$

5.7.2 1.00 " Dia Connecting Rod Section

$$A_{rod} := \pi \cdot \left(\frac{1.0}{2} \cdot in\right)^2$$

$$A_{rod} = 0.785 \cdot in^2$$

$$I_{rod} := \frac{\pi \cdot (1.0 \cdot in)^4}{64}$$

$$I_{rod} = 0.049 \cdot in^4$$

5.7.3 1.75 " Dia Circular Section

$$A_{Ubolt1} := \pi \cdot \left(\frac{1.75}{2} \cdot in\right)^2$$

$$A_{Ubolt1} = 2.405 \cdot in^2$$

$$I_{Ubolt1} := \frac{\pi \cdot (1.75 \cdot in)^4}{64}$$

$$I_{Ubolt1} = 0.46 \cdot in^4$$

$$Z_{Ubolt1} := \frac{I_{Ubolt1}}{\frac{1.75 \cdot in}{2}} \qquad Z_{Ubolt1} = 0.526 \cdot in^3$$

5.7.4 1.75 " Dia Circular Section with .75" internal thread

$$A_{Ubolt2} := \pi \cdot \left[\left(\frac{1.75}{2} \cdot in\right)^2 - \left(\frac{.75}{2} \cdot in\right)^2\right]$$

$$A_{Ubolt2} = 1.963 \cdot in^2$$

$$I_{Ubolt2} := \frac{\pi \cdot \left[(1.75 \cdot in)^4 - (.75 \cdot in)^4\right]}{64}$$

$$I_{Ubolt2} = 0.445 \cdot in^4$$

$$Z_{Ubolt2} := \frac{I_{Ubolt2}}{\frac{1.75 \cdot in}{2}} \qquad Z_{Ubolt2} = 0.508 \cdot in^3$$

6.0 U-BOLT STRESS CALCULATION

Determing the required O.D. for the threaded section to equal a axial strength of the .75" diameter bolt.

$d_1 := .75 \cdot in$

bolt O. D. $\qquad d_i := .75 \cdot in \qquad$ bolt hole diameter in U-bolt

$d_o := \sqrt{{d_1}^2 + {d_i}^2} \qquad d_o = 1.061 \cdot in \qquad$ required O.D. of threaded section of U-bolt

The actual diameter of the U-bolt is 1.75 with a minimum dimension of 1.5 being accepted on NCR No: 1EXFN-N-02.

6.1 Stress Calculations - curved section

This calculation conservatively assumes that the U-bolt is cantilevered from its center and that that is the only point supported by the riser elbow.

$$\sigma_{Ubolt\_bending} := \frac{Preload_{Ubolt} \cdot 4.265 \cdot in}{Z_{Ubolt1}} \qquad \sigma_{Ubolt\_bending} = 48636 \cdot psi$$

$$\tau_{Ubolt} := \frac{Preload_{Ubolt}}{A_{Ubolt1}} \qquad \tau_{Ubolt} = 2495 \cdot psi$$

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

October 13, 1995

Mr. George A. Hunger, Jr.
Director-Licensing, MC 62A-1
PECO Energy Company
Nuclear Group Headquarters
Correspondence Control Desk
P.O. Box No. 195
Wayne, PA 19087-0195

SUBJECT: REPAIR OF FLAWS FOUND IN CORE SPRAY DOWNCOMER JOINTS, PEACH BOTTOM ATOMIC POWER STATION, UNIT NO. 3 (TAC NO. M92639)

Dear Mr. Hunger:

By letter dated October 9, 1995 as supplemented by letter dated October 12, 1995, you informed the NRC of cracks discovered in the four core spray system downcomers within the Peach Bottom Unit 3 reactor vessel. The cracks were discovered through an inservice visual inspection requested in NRC Bulletin 80-13, "Cracking in Core Spray Spargers." You supplemented the visual inspections with ultrasonic inspections and determined the extent of the cracking as detailed in your October 9, 1995 letter.

In your letters, you informed the staff that you planned to install clamps over the affected sections of piping as permanent repairs to the flaws. Details of the clamp design were included in General Electric Company's (GE) reports GENE-771-99-0295, Revision 2, "Core Spray Line Downcomer Bracket Stress Assessment Report," and GENE-771-98-0295, Revision 2, "Core Spray Line Seismic Assessment Report," which you forwarded in your October 12, 1995 letter. We are aware that installation of the clamps was completed on October 12, 1995.

The GE reports demonstrated that the clamps are sufficiently designed to withstand stresses experienced during normal plant operation, transients and postulated loss-of-coolant accidents and maintain the functionality of the core spray piping. The staff concurs with this conclusion.

Your October 12, 1995 submittal also addressed the impact of expected core spray system leakage within the reactor vessel during a postulated loss-of-coolant accident. With the clamps installed and assuming a 360 degree through-wall crack at the flaw location, you calculated that core spray loop "A" would experience a total of 343 gpm of leakage and the "B" loop would experience a total of 78 gpm of leakage. You concluded that these leakage rates were within the margin between the design flow rate for each loop (6250 gpm at 105 psid) and the nominal loop flow rates assumed in your licensing basis loss-of coolant accident analysis (5000 gpm at 105 psid). The staff concurs with this conclusion.

~~9510200211~~ 4pp

Based on the above, we conclude that operation of the Peach Bottom Unit 3, with cracked but clamped core spray downcomers, is acceptable. Ongoing interaction between the staff and the Boiling Water Reactor Vessel and Internals Project may result in further actions involving individual licensee core spray piping.

If you have any questions on this matter, do not hesitate to contact the NRC Project Manager, Joe Shea, at (301) 415-1428.

Sincerely,

/S/

John F. Stolz, Project Director
Project Directorate I-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket No. 50-278

cc: See next page

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If you have any questions on this matter, do not hesitate to contact the NRC Project Manager, Joe Shea, at (301) 415-1428.

Sincerely,

for

John F. Stolz, Project Director
Project Directorate I-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket No. 50-278

cc: See next page

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Sierra Club
433 Orlando Avenue
State College, PA 16803

95-506

BWRVIP

BWR Vessel &
Internals Project ________ *Issue Management and Resolution*

November 10, 1995

Document Control Desk
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: C. E. Carpenter

Subject: "BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines (BWRVIP-03)," EPRI Report TR-105696, October 1995

Enclosed are ten (10) copies of the document "BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines (BWRVIP-03)," EPRI Report TR-105696, October 1995. This document is being submitted as a means of exchanging information with the NRC for the purpose of supporting generic regulatory improvements related to BWR reactor pressure vessel and internals examinations.

The enclosed document provides guidance regarding examinations of BWR core shroud welds. The report includes data on mockup fabrication, NDE uncertainty measurements and evaluation factors, and procedure standards for ultrasonic examination, eddy current examination and visual examination.

The enclosed report has been endorsed by the BWRVIP, however, this endorsement should not be interpreted as a commitment by all members to a specific course of action. Each member must formally endorse the BWRVIP position for it to become that member's position.

Please note that the enclosed document contains proprietary information. Therefore, a letter requesting the report be withheld from public disclosure and an affidavit describing the basis for withholding this information is provided as Attachment 1.

Representatives of the BWRVIP would be pleased to meet with the NRC staff to discuss any comments or issues related to the enclosed document. If you have any questions on the enclosed document or the general subject it addresses, please call Steve Leonard of Niagara Mohawk Power Company at (315) 349-4039.

Sincerely,

J T Beckham Jr

300006

G004
1/10

J. T. Beckham, Jr.
Southern Nuclear Operating Company
Chairman, BWR Vessel & Internals Project

Reply To: J. T. Beckham, Jr., BWRVIP Chairman, Southern Nuclear Operating Co., 42 Inverness Center Parkway, Birmingham, AL 35242 • (205) 877-7279 • Fax: (205) 802-0393

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MODES,M.C. Region 1 (Post 820201)
RECIP.NAME RECIPIENT AFFILIATION
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August 18, 1995

Mr. D. M. Smith
Senior Vice President-Nuclear
PECO Energy
Nuclear Group Headquarters
Correspondence Control Desk
P. O. Box 195
Wayne, Pennsylvania 19087-0195

Dear Mr. Smith:

SUBJECT: PEACH BOTTOM INSPECTION REPORT NOS. 50-277/95-18 AND 50-278/95-18

This letter transmits the NRC Region I inspection report for the announced safety inspection conducted by Messrs. A. Lohmeier and M. McBrearty of this office during the period July 10-14, 1995, at the Peach Bottom Atomic Power Station in Delta, Pennsylvania. Messrs. Lohmeier and McBrearty discussed the findings of this inspection with members of your staff at the exit meeting on July 14, 1995.

This inspection was directed toward assessment of engineering activities providing for the protection of public health and safety at the Peach Bottom Atomic Power Station (PBAPS). The inspection included review of the procedures and implementation of plant modifications. The inspection conclusions were derived, in part, from interviews with plant personnel, examination of plant records, and observations by the inspectors.

The inspectors noted PBAPS was in a self-imposed stand-down status on all modifications due to several modification-related problems which occurred during the past year. The inspectors found PBAPS was taking decisive action in performing a self-assessment of its modification process. The NRC will monitor the results of the self-assessment during a future inspection.

Good performance was noted in carrying out the specific modifications reviewed by the NRC during this inspection. A long-standing unresolved item related to operating cycle data retention was closed. A proactive program in chronic problem resolution was noted that should prove effective in improving the efficient and safe operation of the plant. The utilization of probabilistic safety assessment techniques to supplement deterministic decisions was noted.

An unresolved problem of vibration of the High Pressure Coolant Injection steam lines on both units was noted by the inspectors. This problem will be considered unresolved by the NRC pending completion of PECO Energy's effort to determine the cause of the vibration and eliminate it.

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Considerable improvement in the effectiveness of the engineering organization was noted since the NEEDS reorganization. The initiatives in improvement of the organization effectiveness are notable and will contribute greatly to the safety of nuclear power generation at PBAPS and protection of the public health and safety.

Within the scope of this inspection, no violations or deviations were observed. No reply to this letter is requested. Thank you for your cooperation.

Sincerely,

Michael C. Modes, Chief
Materials Section
Division of Reactor Safety

Docket Nos. 50-277; 50-278

Enclosure: NRC Region I Inspection Report Nos. 50-277/95-18 and 50-278/95-18

cc w/encl:
G. A. Hunger, Jr., Chairman, Nuclear Review Board and Director, Licensing
G. Rainey, Vice President, Peach Bottom Atomic Power Station
W. H. Smith, III, Vice President, Nuclear Station Support
D. B. Fetters, Director, Nuclear Engineering
C. D. Schaefer, External Operations - Delmarva Power & Light Co.
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DATE	08/18/95		08/ /95		08/18/95		08/18/95		08/ /95	

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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

DOCKET/REPORT NOS.: 50-277/95-18
50-278/95-18

LICENSEE: PECO Energy

FACILITY: Peach Bottom Unit Nos. 2 and 3

DATES: July 10-14, 1995

INSPECTORS: Alfred Lohmeier, Senior Reactor Engineer, MS, DRS
Michael McBrearty, Reactor Engineer, MS, DRS

A. Lohmeier 8-18-95
Alfred Lohmeier, Sr. Reactor Engineer Date
Materials Section
Division of Reactor Safety

APPROVED BY: JR Wiggins for 8-18-95
Michael C. Modes, Chief Date
Materials Section
Division of Reactor Safety

<u>Areas Inspected</u>: Evaluation of PBAPS's process for designing and implementing plant modifications, detailed reviews of several planned and completed plant modifications, evaluation of the effectiveness of engineering in identifying and resolving safety-related engineering issues, evaluation of the effectiveness of the Independent Safety Engineering Group (ISEG), and review of the progress made in resolving items on the chronic equipment/system list.

<u>Results</u>: PECO is undertaking an aggressive self-assessment of its modification process in response to problems encountered with recent design and implementation of modifications over the past year. Good performance was noted in planning and implementing selected modifications reviewed during the inspection period, including valve modifications to eliminate potential pressure-locking, and plans for the repair of a crack in the core spray downcomer. The ISEG is effective in providing insight into many areas in which improvement would enhance the safe operation of the plant, such as the use of Probabilistic Safety Assessments (PSA) in planning and scheduling plant changes. The inspectors determined PBAPS has an effective process for identifying and resolving chronic equipment/systems problems. In resolution of URI 90-014-02, cumulative fatigue usage factors attained by primary system components at the present time remain within allowable limits. PBAPS is currently implementing a systematic method for retrieval and evaluation of cyclic data. URI 90-014-02 is closed. HPCI system piping in both units is experiencing high vibration levels due to unknown causes. In a new URI 95-018-01, PBAPS will determine the cause of the vibration and eliminate it.

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Q PDR

DETAILS

1.0 SCOPE OF INSPECTION (INSPECTION PROCEDURE 37550)

This inspection was conducted at the Peach Bottom Atomic Power Station (PBAPS) of PECO Energy in Delta, Pennsylvania, during the week of July 10, 1995, to assess the effectiveness of the engineering activity at PBAPS in providing for the protection of public health and safety. The scope of the inspection included the evaluation of PBAPS's process for designing and implementing plant modifications, detailed reviews of several planned and completed plant modifications, evaluation of the effectiveness of engineering in identifying and resolving safety-related engineering issues, evaluation of the effectiveness of the Independent Safety Engineering Group (ISEG) in identifying and monitoring resolution of safety issues, application of probabilistic safety analysis to supplement deterministic problem resolution, and evaluation of the progress made in resolving chronic equipment/system problems.

2.0 REVIEW OF PLANT MODIFICATION IMPLEMENTATION

The inspectors determined that PECO Energy is implementing an aggressive self-assessment program at PBAPS to identify weaknesses in its modification process that contributed to several modification problems over the past year, and is actively revising the current modification process to preclude further problems. The inspectors also assessed PECO's modification-related activities in resolving potential pressure locking of safety-related gate valves, and the proposed repair of cracking found in the (D) downcomer of the Unit 3 (B) core spray loop.

2.1 PBAPS Self-Assessment of Modification Process

At the time of the inspection, PBAPS was nearing the end of a self-imposed stand-down (cessation of activity) on all plant modifications. This cessation was enacted as a result of several modification implementation problems encountered over the past year. The most recent problem that precipitated the stand-down was identified on June 20, 1995. It involved a modification of the Emergency Diesel Generators (EDG). This issue was fully reviewed by the resident inspectors, and is discussed in detail in their routine Inspection Report 95-11. Because the internal review was already in progress when the inspectors arrived on site, this inspection focused on review of PBAPS's self-assessment activities in identifying and resolving the weaknesses in its modification program.

There are several activities at PBAPS that are under the broad scope of modifications affected by the stand-down. These include major modifications, small modifications (SM), design equivalent changes (DEC), minor physical changes (MPC), rework/repair non-conformance reports (NCR), and temporary plant alterations (TPA). In order to identify possible weaknesses in its program, PBAPS convened a task force consisting of plant personnel selected from a cross-section of the disciplines involved in the modification process. The objective of the task force was to review the overall process in order to identify and understand the possible weaknesses which have led to the recent

problems. The task force determined that in nearly all the instances involving problematic modifications, the problems were primarily due to human factors. Moreover, the task force found that current procedures, if properly followed, would have prevented the occurrence of the problems.

For example, in the case of the EDGs, the initiating event which led to the problem was an error in the EDG electrical wiring diagram. PBAPS indicated that current modification procedures at PBAPS require that an as-built walkdown be conducted prior to the design and installation of the modification in order to identify any drawing errors. During the implementation of the EDG modification, PBAPS stated that the drawing error was actually noted during the as-built walkdown, but for yet to be determined reasons, the error was never reported back to the design engineering section.

As a result of the task force findings, PBAPS issued Administrative Guide AG-123, "Maintaining Configuration Control of Design Changes," effective July 11, 1995. The procedure contains several checklists for the design, installation, and testing/turnover phases of the modification process. For each item on the checklists, the procedure provides an explanation of the types of attributes addressed by the item, together with practical examples. PBAPS indicated that all the checklist items were developed from various portions of current procedures associated with the modification process. AG-123 will be implemented on all future modifications, and will be used to re-review selected modifications previously implemented. PBAPS acknowledged that it will require a period of time to determine the effectiveness of the new procedure in reducing problems with plant modifications. PBAPS will assess the implementation of the revised procedure in August 1995.

The inspector concluded that it was a strength that PECO recognized the problems with modification implementation. PECO took concise action in enacting the modification stand-down, and is continuing with a critical self-assessment of its current process. Based on discussions with PBAPS personnel and on review of revised procedure AG-123, the inspectors determined that PECO is aggressively trying to identify and eliminate problems with the design and implementation of plant modifications.

2.2 Pressure Locking of Safety-Related Gate Valves

The inspectors performed a review of PECO's modification-related activities for resolving potential pressure-locking of motor-operated gate valves. The extent of this effort included discussions with site engineering personnel, and detailed reviews of planned and completed modification packages. PECO's methodology for determining valve susceptibility to pressure-locking and the associated valve operability determinations were discussed, in part, in Inspection Report 50-277;278/94-012, and are still being followed as part of URI 94-012-04.

The inspectors held discussions with cognizant individuals from PBAPS component and design engineering sections. Component Engineering has the responsibility for assessing gate valves, and identifying which valves may be susceptible to pressure-locking. The Design Engineering Section has the responsibility for developing and implementing preemptive repairs for those

valves which are susceptible. From these discussions, the inspectors found that pressure-locking concerns are addressed at PBAPS by one of two equally effective methods: (1) a bypass line may be installed to vent the valve bonnet cavity pressure to the opposite side of the valve discs; and (2) a pressure relief hole is drilled in the disc such that pressure fluid cannot be trapped in the valve bonnet. PECO indicated that the actual method selected is generally based on the valve size, type, and geometry, and on accessibility to the valve internals. For example, if a valve is scheduled for in-body maintenance during the outage, the preferred fix would be to drill the relief hole since valve disassembly was already planned. Otherwise, installation of a bypass line would be preferred.

Based on these discussions, the inspectors found that the individuals demonstrated an understanding of the pressure-locking phenomenon, and of the appropriate preemptive solutions to it.

2.2.1 Valve Bonnet Cavity Bypass Modification

The inspectors reviewed Modification P00444, which includes the details for installing small-bore bypass lines to vent the valve bonnet cavity for eight of the eleven valves identified as being susceptible to pressure-locking. The modification was implemented in Unit 2 during refueling outage 2R10, and will be implemented in Unit 3 during refueling outage 3R10. Based on this review, the inspectors determined that the modification package was well documented, is consistent with the appropriate design criteria, identified the appropriate in-service inspection (ISI) and in-service testing (IST) requirements, and had undergone the appropriate levels of review and approval. Additionally, the 10 CFR 50.59 evaluation was found to be technically adequate.

From the list of valves included in the scope of modification P00444, two completed Unit 2 valve modifications were selected for more detailed review. Specifically, the inspector reviewed the Engineering Change Requests (ECR) and associated Action Requests (A/R) for the installation of bypass lines on MO-2-10-025A, the inboard discharge valve for the A loop of the Residual Heat Removal System, and on MO-2-23-019, the High Pressure Coolant Injection (HPCI) Valve. Based on this review, the inspectors found that the ECRs provided comprehensive descriptions of the installation and testing requirements, including materials, storage and handling, cleanliness, acceptance test plans, and any needed evaluations to determine the overall impact on operations and station controlled procedures and programs. Additionally, the inspectors determined that the modifications were consistent with the design bases for the valves and associated piping, and that the affected Design Basis Documents (DBD), Piping and Instrumentation Drawings (P&ID), and Inservice Inspection (ISI) Drawings had been properly revised to reflect the modification.

2.2.2 Valve Wedge Pressure Relief Hole Engineering Change Request (ECR)

This ECR specified the drilling of a pressure relief hole in the flexible wedge of the Unit 2 Reactor Core Isolation Cooling discharge valve to the B Feedwater Line, MO-2-13-021, and was implemented during refueling outage 2R10. The inspectors found the modification package was well documented, consistent with the appropriate design criteria, identified appropriate in-service

inspection and in-service testing requirements, and had undergone the appropriate levels of review and approval. Further, the inspectors determined that PECO Energy had performed an adequate 10 CFR 50.59 safety evaluation to support implementation of the modification. The affected Design Basis Documents (DBD), Piping and Instrumentation Drawings (P&ID), and ISI Drawings had been properly revised to reflect the addition of the relief hole.

As part of this effort, the inspectors also reviewed Maintenance Procedure M-510-604, "Walworth Mark 10 and 14 Seal Gate Valve Maintenance." This is the required procedure for performing maintenance on MO-2-13-021. The inspectors determined that PECO Energy had properly revised the procedure so that it alerted maintenance personnel of the addition of the relief hole and the need to drill a new hole should the wedge be replaced during maintenance activities. The procedure instructed maintenance personnel to inspect the hole for any debris. It also described the proper orientation of the hole during valve reassembly.

2.3 Repair of Core Spray Downcomer

PBAPS discovered a 3 inch linear crack in the (D) downcomer of the (B) core spray loop during refueling outage 3R09. An analysis provided justification for continued operation through the next operating cycle. The repair modification under development and committed to USNRC prior to refueling outage 3R10 must be a long-term solution to ensure that the downcomer piping would not separate on core spray initiation.

2.3.1 Proposed Modification

The proposed modification installs a mechanical clamp on the 172.5 degree core spray downcomer (CSD) in the Peach Bottom Unit 3 Reactor Pressure Vessel. PBAPS believes the clamp is a permanent repair for the crack found in the welded sleeve connecting the downcomer to the core spray piping entering the shroud at 172.5 degrees. The clamp also allowed for additional cracking to the extent of 360 degrees through wall at the sleeve spigot weld, the spigot/pipe weld, below the pipe sleeve weld (the current detected crack), and the pipe/elbow weld just above the shroud penetration.

2.3.2 Nature of the Crack

The inspections performed in response to Bulletin USNRC 80-13 identified a crack indication in the vertical section (downcomer) of the core spray line outside the shroud but inside the reactor pressure vessel where two sections of piping meet and are connected by two circumferentially welded sleeves at the 172.5 degree azmithal location of the shroud. The crack is about 3.0 inches in length and 2.5 inches below the uppermost connection weld in the heat affected zone of the weld. The crack is believed to be caused by intergranular stress corrosion (IGSCC).

Analysis performed of the CSD concluded the system would remain operable through the next operating cycle, until refueling outage 3R10. The analysis considered crack growth rates, leakage through the affected area, consequences of a 360° through-wall crack propagation, loose parts, CSD structural integrity, and a nominal Safer/GESTR-LOCA analysis with failure of the core spray line.

2.3.3 Results of Engineering Evaluation

PECO Energy determined the clamp design will prevent separation of the core spray downcomer from the shroud inlet piping. The estimated leakage occurring from the worst case cracking is within margins required to maintain adequate core spray flow to the reactor core during all design basis accidents. The clamp is designed for a 40 year life in conformance with ASME Boiler and Pressure Vessel Code, Section NG (1989 Edition), as a guide for design and analysis. The repair clamp is classified as safety-related and can withstand the same design basis loads as the current CSD under normal and abnormal operating conditions. The installation will not degrade other reactor pressure vessel internals. Provisions for additional cracking of the CSD (above the CSD) were not incorporated into the design because of additional cost, schedular impact, and low probability of crack development in this region. The clamp can be adapted to the remaining three Unit 3 downcomer spigot/sleeve joints and the four Unit 2 downcomer spigot/sleeve joints with little or no modification.

2.3.4 Assessment of Proposed Repair Program

Review of the Engineering Change Request (ECR) printout by the inspectors included proposed inspection, installation instructions, material, dynamic qualification, drawing change disposition, procedures, specification revisions, fire protection review checklist, planned mock-up testing, ALARA review, acceptance testing, 10 CFR 50.59 review, design information documentation (DID), stress analysis, fabrication specification, and project instructions. The contractor of choice (General Electric Company) will perform the repairs. The inspectors found the proposed modification of core spray downcomer to be comprehensively developed by PECO Energy. The proposed repair program, including the modification design, is currently under review at NRR.

3.0 PERFORMANCE ASSESSMENT OF ENGINEERING ACTIVITY

The inspectors determined that the Independent Safety Engineering Group (ISEG) is effective in providing insight into many areas in which improvement would enhance the safe operation of the plant, especially application of probabilistic safety analyses in scheduling and planning plant changes. It was also found that PECO has an effective process for identifying and tracking chronic equipment and systems problems, and has made reasonable progress in resolving these problems over the past year.

3.1 Independent Safety Engineering Group Performance Assessment

The ISEG, reporting to PECO Energy Headquarters, provides PBAPS with independent audits of engineering functions through assessment of a wide range of engineering issues. The issues are reflected in the reports issued over the present SALP period reviewed by the inspector during the inspection. The issues included Review of Calculations and Computations Supporting Peach Bottom Small Modifications, Review of Control Room Entries into Abnormal Operating Procedures, Mispositioning of Control Rod During SCRAM Time Testing, Review of Operability Determinations, Voltage Rating of Electrical Components in the 125 Volt DC System, Responses to a Sudden Steam Leak in Unit 3 Primary Containment, Review of Control Rod SCRAM Requirements, Reactivity Management Events, and Probabilistic Safety Assessment Concepts and Analyses in Evaluating Plant Changes.

The inspectors found these reports were well written. They gave insight into many areas in which improvement would enhance the safe operation of the plant. Recommendations were given to the audited departments and a system of monitoring the recommended action was implemented.

An example of the ISEG activity was their assessment of PECO's utilization of Probabilistic Safety Analysis in decision making at the plant. The reports gave case examples comparing the effect of decision making with and without using PSA to augment the traditional deterministic approach to evaluation of proposed plant changes. In other cases, an evaluation of secondary containment breach during fire, and the effect of the risk impact of HPCI 4 day LCO used PSA in the evaluation process. PSA was furthermore used in review of events requiring operability decisions.

On the basis of the inspector's review of Peach Bottom ISEG activity, it was found that the findings and recommendations of ISEG in areas fundamental to safe operation of the facility are used at Peach Bottom to supplement deterministic evaluation procedures.

3.2 Chronic System Problem Resolution

PECO site engineering developed the chronic equipment/system problem list to identify areas where engineering should focus its resources to improve equipment and system reliability. The inspectors revisited the list of chronic equipment/system problems to determine PBAPS's progress in addressing these issues over the past year. The list has been expanded from three general categories to five. The original problem categories included: (A) Problems Requiring Engineering Action/Implementation Plans, (B) Problems Awaiting Implementation, and (C) Fully-Resolved Problems. The new problem categories included: (D) Operator Work Arounds, and (E) Fully-Resolved Work Arounds. For the original three problem categories, the list provides a description of each problem, the action required for solution, the next action to be performed, and the status relative to completion. For the two new categories, the list provides a description of the problem, the action

required for solution, the next action to be performed, and the responsible individual. It is noted that the problems on the list are self-identified, and include both safety-related and nonsafety-related issues. None of the problems currently on the list were determined by PBAPS to pose a threat to nuclear safety.

The inspectors attended the July 11, 1995, morning management meeting during which PBAPS site engineering presented the current status of items included on the list. In addition, the inspectors met with the manager responsible for maintaining the list, and reviewed the monthly status reports for approximately the past year. The inspectors determined that PBAPS had made considerable progress in addressing the items on the list. Five of the 19 items in Category A had been fully resolved. An additional five items listed in Category A had been moved to Category B, in which a resolution plan was developed and scheduled for implementation. Two new items had been added to Category A (Steam Jet Air Ejectors and the Off-Gas System). Six of the nine Category B issues had been fully resolved, and one new issue (Neutron Monitoring System Power Supplies) was added. PBAPS has developed plans for resolving all new issues.

The two new problem categories involving operator work arounds were developed as a result of discussions with Operations personnel. Engineering surveyed the Operations personnel for a list of work around issues which tend to complicate day-to-day operations. This list was then assessed to identify the most critical issues that could be resolved through actions by site engineering. These items were added to the chronic equipment/system problem list to ensure that each was given the proper engineering and management attention.

The inspectors concluded that PBAPS had an effective process for identifying chronic equipment/systems problems, had specific plans and schedules for resolving each item on the list, and had made reasonable progress in fully resolving these problems over the past year. The inspectors will continue to monitor PBAPS's progress in addressing the list during future inspections.

4.0 REVIEW OF ENGINEERING ISSUE RESOLUTION

The inspectors reviewed several significant engineering issues including: (1) preparations for the Unit 3 core shroud examination, and installation of a repair contingency; (2) resolution of URI 90-14-02, relating to fatigue monitoring; and (3) assessment of vibrations observed on the High Pressure Coolant Injection System (HPCI). The review focused on the performance of the engineering personnel in identifying the issue, determining the corrective action required to resolve the issue, and implementing the corrective action in an effective manner. The inspectors determined that PBAPS is well prepared for performing the shroud inspections, and, if necessary, for implementing a repair designed by General Electric. PBAPS's activities in addressing URI 90-14-02 were sufficient to close the issue. PBAPS has not been successful in identifying the cause of vibrations on the HPCI steam line; this was declared an unresolved issue.

4.1 Unit 3 Reactor Core Shroud Examination and Repair Contingency

The inspectors determined that PBAPS is well prepared to perform the Unit 3 core shroud inspections, and, if necessary, install a shroud repair, during refueling outage 3R10. Discussions were held with PECO's lead engineer responsible for developing and overseeing the shroud examinations. The individual is an active member of the Boiling Water Reactor Vessel and Internals Project (BWRVIP) task group reviewing the core shroud cracking issue. Based on the discussions, the inspectors determined that the individual demonstrated a clear recognition of the seriousness of the problem, and also demonstrated a very strong technical understanding of the issue.

In accordance with Generic Letter 94-03, PBAPS submitted its plans for performing the Unit 3 shroud inspections to the NRC on June 16, 1995. PECO will essentially use the same examination plan which was utilized in assessing the Unit 2 shroud during refueling outage 2R10. If necessary, PBAPS is prepared to implement modification P00435 which is a GE-designed shroud repair plan consisting of stabilizer tie-rods designed to hold the core shroud in place and mitigate the effect of further IGSCC crack propagation, should it occur. The repair hardware has been procured and will be ready for installation, if needed. The shroud examination plans and the engineering analysis of the repair is currently under review at NRR.

4.2 Fatigue Monitoring Program (URI 90-14-02)

Background

Inspection Report 50-277/278/90-14 reported that the B recirculation loop of Unit 3 had experienced an excessive heatup during which reverse flow was suddenly initiated and the B loop temperature rose from 105 to 266°F in 18 minutes. General Electric conservatively classified the event as an improper start of an idle recirculation loop. Peach Bottom Nuclear Engineering determined that continued operation was permissible because the vessel is analyzed for 5 events and believed that only one additional event of this type had previously been experienced. Since the tracking of these occurrences was weak at Peach Bottom, the NRC believed a confirmatory review was warranted.

Operating Procedure ST 12.4, "Reactor Pressure Vessel Transients - Cycles Record," tracked various thermal/hydraulic events, but did not include improper idle recirculation loop starts. Other types of events for which a limit is specified were also not tracked. The SRI noted that the licensee was working to revise the system and update the data. It was believed a historical review of recorder charts and logs might be required. The NRC declared that the resolution of this issue remain unresolved, pending completion of the licensee's review (50-277/90-14-01).

During a safety inspection 50-277/278/93-18, the NRC inspector found the Technical Specification (TS) 6.10.2(f) requires "records of transient or operating cycles for those facility components designed for a limited number of transients or cycles be retained for the life of the facility."

Examination of the system used by the licensee to collect, retain, and disseminate operational data indicated that the operational data was temporarily stored in the form of strip charts and logs, and subsequently shipped to a permanent retention site in Pittsburgh.

The licensee, recognizing the shortcoming of the cycle monitoring system, had retained General Electric Company (GE) to perform an reevaluation of the primary system cyclic history in terms of its effect on primary system components. The cyclic data used in this evaluation was from 1984 to 1993. The inspector found that the plant operation began prior to this date, and the GE evaluation included backward extrapolation of data, based on the characteristic of present cyclic operation.

Current Inspection Findings

The inspector found that PBAPS had developed a Reactor Pressure Vessel Transient Cycles Recording Procedure ST-J-080-940 for PBAPS Units 2 and 3 which recorded the number of reactor pressure vessel cycles occurring over 6 month periods and maintain a cumulative total of reactor pressure vessel cycles since the beginning of operation. The numbers of cycles are retained for boltup/unbolting, hydrostatic tests, heatup/cooldown, turbine roll, power cycles, turbine trips, feedwater heater bypass, scrams with loss of feedwater heater pumps and main steam isolation valve closure, generator trip, reactor overpressure with delayed scram, improper reactor loop starts, sudden recirculation loop starts, excessive heatups, feedwater temperature reduction, HPCI/RCIC injection, shutdown cooling in service, and excessive cooldown events. The running total is compared to the cycles to which the system components were designed.

The inspector found that the classification of the transient event that initiated this unresolved item URI 50-277/90-14-02 was completed and the event duly recorded as an improper start of the recirculation loop.

Review of the running totals of reactor pressure vessel cyclic events by the inspector, as compared to the total events to which primary components were designed, indicated that the events were reasonably within the expected numbers of design events. Therefore, the calculated cumulative usage factors remain within the limit of 1.0.

Conclusion

The inspectors found that PECO has taken appropriate corrective actions in response to the NRC's concerns with fatigue monitoring which were delineated in IR 50-277;278/90-14 and IR 50-277;278/93-18. On this basis, URI 50-277/90-14-02 is closed.

4.3 HPCI Steam Supply Line Vibrations (NCR PB 94-000960)

Background

The inspectors reviewed PECO Energy progress in resolving the HPCI steam line vibration found in Unit 3 (reported in IR 50-277/278/94-17). The licensee has continued their study of the issue since that time with the assistance of a contractor (Stone and Webster) with experience in evaluation of a similar vibration problem at another plant (Quad Cities). On the basis of an extensive study of the vibrating pipe, the contractor concluded that the HPCI steam line vibration is due to some flow disturbance in the main steam line to which the HPCI line is connected. The contractor did not identify the source of the disturbance. The contractor concluded that the level of cyclic stress in the vibrating pipe was below the endurance limit of the pipe material. On this basis, the licensee believed it not to be immediately necessary to eliminate the source of vibration.

Inspection Findings

The inspectors walked down the HPCI piping system and observed that the Unit 3 vibration was visibly observable and of a magnitude (visually) to warrant further investigation. A similar observation was made by the senior resident inspector on Unit 2. Discussions with the licensee and resident inspectors indicated that the level of vibration changed with changes in power. Continued operation with the vibrating HPCI steam lines in both Units 2 and 3 has been justified by the licensee through fatigue analysis. However, the inspector believed it appropriate for the licensee to continue the steam line vibration investigation toward determining the root cause of the vibration in order to preclude fatigue failure of the steam line should the levels of vibration increase. The results of this investigation will be followed by the NRC in future inspections. The inspectors believed it important that the cause of the vibration be determined and eliminated.

Corrective Action

The vibration of the HPCI steam line was monitored by visual observation of the vibrating pipe and instrumentation attached thereto. If the source of vibration is to be determined, PECO Energy found that it would be necessary to monitor the main steam line pipe to which the HPCI steam line is connected. The licensee will continue in the investigation of the root cause of the HPCI steam line vibration.

Conclusions

On the basis of the indeterminate root cause of the vibration, the observed level of vibration, and the assessment by the licensee that the stresses were not of a level causing fatigue damage, the inspectors declared this to be an unresolved item URI 95-018-001, such that the cause of vibration will be determined and eliminated.

5.0 SUMMARY AND CONCLUSIONS

- PECO is implementing an aggressive self-assessment program at PBAPS to identify weaknesses in its modification process that contributed to several modification problems over the past year. PBAPS is actively revising the current modification process to preclude further problems.

- PBAPS demonstrated good performance in modification-related activities for resolving potential pressure locking of safety-related gate valves, and the proposed repair of cracking found in the (D) downcomer in the Unit 3 (B) core spray loop.

- The ISEG is effective in providing insight into many areas in which improvement would enhance the safe operation of the plant, especially application of probabilistic safety analyses in scheduling and planning plant changes.

- PBAPS has an effective process for identifying and tracking chronic equipment and systems problems, and has made reasonable progress in resolving them over the past year.

- PBAPS is adequately prepared for performing the Unit 3 shroud inspections, and, if necessary, for implementing a repair contingency.

- PBAPS appropriately addressed the obtaining, recording, and retention of operating cycle data in accordance with Technical Specification Section 6.10.2(f). URI 90-14-02 is recommended for closure.

- PBAPS has not been successful in identifying the cause of vibrations on the HPCI steam line. This is declared an unresolved item URI 50-277/95-018-01 pending determination of the root cause of vibration and eliminating it.

6.0 MANAGEMENT MEETINGS

The inspectors met with licensee representatives at the entrance meeting on July 10, 1995, and at the exit meeting on July 14, 1995, at the Peach Bottom Atomic Power Station in Delta, Pennsylvania. The names of licensee personnel contacted are shown on Attachment A.

The findings of the inspection were discussed with licensee management at the exit meeting. The licensee did not disagree with the findings of the inspectors.

Attachment - Persons Contacted

ATTACHMENT

Personnel Contacted During the Inspection

PECO ENERGY COMPANY

*	H.	Abendroth	Engineer	Atlantic Electric
	R.	Andrews	Engineer	Experience Assessment
	J.	Armstrong	Sr. Manager	Plant Engineering
*	F.	Cook	Sr. Manager	Design Engineering
*	P.	Davison	Manager	Plant Engineering
*	G.	Edwards	Plant Manager	PBAPS
	D.	Foss	Engineer	Experience Assessment
	V.	Gilbert	Manager	Operations Support
	M.	Hammond	Manager	Performance and Reliability
	G.	Hunger	Director	Licensing
*	M.	Kelly	Manager	ISEG
*	O.	Limpias	Manager	Civil/Structural Design Engineering
*	S.	Mannix	Manager	Industrial Risk Management
*	T.	Mitchell	Director	Site Engineering
	T.	Moore	Manager	Component Engineering
*	W.	Nelle	Lead Assessor	NQA
*	A.	Piha	Engineer	Design Engineering
	F.	Polaski	Manager	Project Engineering
	D.	Schra	Engineer	ISEG
*	R.	Smith	Engineer	Experience Assessment
	K.	Tom	Engineer	Mechanical Design Engineering

U.S. NUCLEAR REGULATORY COMMISSION

*	W.	Schmidt	SRI	NRC Region I

* Indicates attendance at the exit meeting July 14, 1994.

DrS

September 29, 1994

Mr. D. M. Smith
Senior Vice President-Nuclear
PECO Energy Company
Correspondence Control Desk
P. O. Box 195
Wayne, PA 19087-0195

Dear Mr. Smith:

SUBJECT: SPECIAL SAFETY INSPECTION 50-277/94-24 AND 50-278/94-24

This letter transmits the findings of the special safety inspection conducted by Messrs. R. K. Lorson and W. L. Schmidt from September 7 through September 14, 1994, at the Peach Bottom Atomic Power Station, Delta, Pennsylvania. The inspectors conducted this review after identifying that an August 3, 1994, maintenance activity placed the safety-related emergency service water system for both units in an unanalyzed configuration that affected the cooling water flow to safety-related components for both units. Mr. Lorson discussed the inspection findings, documented in the enclosed report, with Mr. G. Rainey and other members of your staff on September 15, 1994.

The inspectors identified, during normal activities, that on August 3, 1994, PECO Energy personnel unknowingly placed the emergency cooling water system in a configuration that prevented safety-related equipment from receiving design cooling water flowrates. Maintenance staff, with the concurrence of Operations personnel, shut and de-energized the emergency service water system discharge valve (MO-498) to the Conowingo Pond for approximately 50 minutes and did not have a procedure nor personnel stationed to immediately reopen the valve if necessary during an accident condition. This aligned the emergency service water system discharge to the emergency cooling tower which is approximately 44 feet higher than the normal flow path with both emergency service water booster pumps out of service, this would have resulted in a reduction of emergency service water flow to below the design flowrates for the emergency diesel generators and emergency core cooling system room and pump coolers.

The overall safety consequence of this event was small since no conditions occurred that required the use of the emergency diesel generators or core cooling systems, during the time that valve MO-498 was shut; however, this condition represented a significant degradation in plant safety, since the lower than design flows could have affected the operability of the emergency diesel generators and core cooling systems in the event of a design basis accident. Coincidentally, had the operators recognized this condition, the technical specifications would have required that both units be shutdown within six hours.

Based on the results of the inspection, three apparent violations were identified and are being considered for escalated enforcement action, in accordance with the "General Statement of Policy and Procedure for Enforcement

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Actions" (Enforcement Policy), 10 CFR Part 2, Appendix C. Specifically:

- The maintenance activity on valve MO-498 was conducted without an adequate safety review to determine that the activity did not represent an unreviewed safety question and appears to be a violation of the requirements of 10 CFR 50.59.

- Procedures were not in place to ensure that the emergency service water system would be able to perform its design function in the event of an accident. Procedures specifying that MO-498 needed to be opened in the event of an accident were not in place prior to the maintenance activity. This was significant given the importance of the MO-498 valve and the nature of the maintenance activity (VOTES testing) where the component had the potential to be left closed for an extended time. This was an apparent violation of 10 CFR 50, Appendix B, Criterion III, Design Controls.

- During the Performance Enhancement Program review of the August 3, 1994 emergency cooling tower basin overflow, caused by the ESW alignment to the tower, PECO Energy did not identify that closing MO-498 altered the emergency service water system flow path and thus affected the flow rates to safety-related components. Rather, PECO Energy staff focused on the emergency cooling tower overflowing, not on any potential safety effects of the closure of MO-498. This represented an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions.

Accordingly, because these are apparent violations, no Notice of Violation is presently being issued for these inspection findings. In addition, please be advised that the number and characterization of the apparent violations described in the enclosed inspection report may change as a result of further NRC review.

A closed enforcement conference to discuss these apparent violations has been scheduled for 9:30 a.m. on October 18, 1994, in the Region I office. The decision to hold an enforcement conference does not mean that the NRC has determined that a violation has occurred or that enforcement action will be taken. The purposes of this conference are to discuss the apparent violations, their causes and safety significance; to provide you the opportunity to point out any errors in our inspection report; and to discuss any other information that will help us determine the appropriate enforcement action in accordance with the enforcement policy. In particular, at the conference please be prepared to discuss the effects of closing MO-498 on the operability of the emergency diesel generators and the emergency core cooling equipment with respect to your design basis accident assumptions. Additionally, be prepared to address the actions taken or planned to ensure: 1) that your Maintenance and Engineering staffs properly plan and evaluate the potential safety significance of maintenance activities before presentation to the Operations department for authorization; 2) that the Operations staff fully reviews, considers the plant safety impacts, and ensures that necessary procedures are in place before authorizing maintenance activities.

In addition, the conference is an opportunity for you to provide any information concerning your perspectives on 1) the severity of the violations, 2) the application of the factors that the NRC considers when it determines the amount of a civil penalty that may be assessed in accordance with Section VI.B.2 of the Enforcement Policy, and 3) any other application of the Enforcement Policy to this case, including the exercise of discretion in accordance with Section VII. You will be advised by separate correspondence of the results of our deliberations on this matter. No response regarding these apparent violations is required at this time.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room.

We appreciate your cooperation.

Sincerely,

ORIGINAL SIGNED BY
WAYNE D. LANNING

for Richard W. Cooper, II, Director
Division of Reactor Projects

Docket/License No. 50-277/DPR-44
50-278/DPR-56

Enforcement Action 94-197

Enclosure:
1. NRC Region I Special Inspection Report 50-277/94-24 and 50-278/94-24

cc w/encl:
J. Doering, Chairman, Nuclear Review Board
G. Rainey, Vice President, Peach Bottom Atomic Power Station
W. H. Smith, Vice President, Nuclear Services Department
D. Fetters, General Manager, Nuclear Engineering Division
C. Schaefer, External Operations-Nuclear, Delmarva Power & Light Co.
G. Edwards, Plant Manager, Peach Bottom Atomic Power Station
A. J. Wasong, Manager Experience Assessment, Peach Bottom Atomic Power Station
G. A. Hunger, Jr., Manager, Licensing Section
J. W. Durham, Sr., Senior Vice President and General Counsel
J. A. Isabella, Director, Generation Projects Department, Atlantic Electric
B. Gorman, Manager, External Affairs
R. McLean, Power Plant Siting, Nuclear Evaluations
D. Poulson, Secretary of Harford County Council
R. Ochs, Maryland Safe Energy Coalition
J. H. Walter, Chief Engineer, Public Service Commission of Maryland
Public Document Room (PDR)
Local Public Document Room (LPDR)
Nuclear Safety Information Center (NSIC)
K. Abraham, PAO (2)
NRC Resident Inspector
Commonwealth of Pennsylvania
TMI - Alert (TMIA)

bcc w/encl:
Region I Docket Room (with concurrences)
K. Gallagher, DRP

bcc w/encl via E-Mail:
W. Dean, OEDO
J. Shea, NRR
M. Thadani, PDI-2, NRR
M. Shannon, ILPB
D. Holody, EO, RI

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DATE	09/28/94		09/28/94		9/29/94			

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U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/94-24 50-278/94-24	License Nos. DPR-44 DPR-56
Licensee:	PECO Energy Company P. O. Box 195 Wayne, PA 19087-0195	
Facility Name:	Peach Bottom Atomic Power Station Units 2 and 3	
Dates:	September 7 - September 14, 1994	
Inspectors:	R. K. Lorson, Resident Inspector (Lead) W. L. Schmidt, Senior Resident Inspector	
Approved By:	Clifford J. Anderson C. J. Anderson, Chief Reactor Projects Section 2B Division of Reactor Projects	9/26/94 Date

EXECUTIVE SUMMARY
Peach Bottom Atomic Power Station
Special Inspection Report 94-24

The inspectors identified that PECO Energy did not adequately control a maintenance activity on an emergency service water (ESW) valve. Specifically, PECO Energy shut and deenergized the ESW discharge valve (MO-498) to the Conowingo Pond for approximately 50 minutes and did not have a procedure nor personnel stationed to immediately reopen the valve if necessary during an accident condition. This isolated the normal ESW discharge path to the Conowingo Pond. If ESW had been needed to support emergency diesel generators (EDG) or ECCS equipment operation, the flow path would have been to the emergency cooling tower (ECT). The increased elevation to the ECT would have caused an unknown reduction of ESW flow, to below the design flowrates, to the EDGs and the emergency core cooling systems (ECCS) pump and room coolers. This resulted in a significant degradation to plant safety and a potential challenge to the operability of the EDGs and ECCS equipment. The inspectors identified the following concerns related to this activity (Section 3.2):

- PECO Energy did not perform a safety evaluation as required by 10 CFR 50.59 prior to placing the ESW system in an unanalyzed configuration. This reduced the ESW system flowrates and potentially impacted the operability of the EDGs and ECCS equipment.

- PECO Energy did not implement adequate procedures for this activity to ensure that the design requirements for the ESW system were maintained.

- PECO Energy's corrective action process focused on a non-safety significant symptom of the problem and failed to identify the potential operability issues related to this activity.

The above issues are apparent violations of regulatory requirements as described in the enclosed report and are being considered for escalated enforcement.

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DETAILS

1.0 INTRODUCTION AND SCOPE

The inspectors reviewed an August 3, 1994, event where PECO Energy placed the emergency service water (ESW) system into an unanalyzed configuration during a preventive maintenance activity. At the time of this event, Unit 3 was operating at 100% power and Unit 2 was operating at approximately 82% power due to end of cycle coastdown operation. During motor operated valve diagnostic testing (VOTES) on the ESW valve (MO-498) return to the discharge pond, the normally open valve was shut and de-energized for approximately 50 minutes. This placed the ESW system into an unanalyzed configuration. PECO Energy did not have a procedure nor have personnel stationed to immediately reopen the valve if necessary during an accident condition.

The inspectors interviewed personnel and reviewed documents to determine:

- The ESW system design requirements.
- The event sequence, including control of the maintenance activity.
- The effects of the maintenance activity and its safety significance.
- The effectiveness of interim corrective actions.
- If any regulatory requirements were not met.

2.0 EMERGENCY SERVICE WATER SYSTEM OPERATION (71707)

A basic diagram of the ESW system is included as Attachment I.

2.1 Design Basis Operation

In the event of the design basis accident (DBA) loss of coolant with a loss of offsite power (LOCA/LOOP), the ESW system is required to provide cooling to the emergency diesel generators (EDGs) and the emergency core cooling system (ECCS) pump/room coolers. The flowpath (open loop) is from the A or B ESW pump through the ESW cooled loads, exiting to the discharge pond through valve MO-498. During normal plant operation, when the ESW pumps are not running, the ECCS pump/room coolers receive flow from the non-safety related service water (SW) system. The ESW pumps are designed to automatically start within 36 seconds of an EDG start to cool the ESW system loads. The non-safety related SW system would be unavailable due to loss of offsite power, following the DBA.

The four EDGs require ESW flow to remove heat generated during operation from the internal cooling water, the scavenging air, and lubrication oil systems. If ESW flow is not sufficient to remove this heat, EDG damage would occur resulting in a loss of power to the associated ECCS equipment.

All ECCS pump rooms have internal cooling units which maintain the general area temperatures when the pumps are running. These cooling units, along with the necessary ESW flow, are required by technical specification for operability of each specific ECCS pump. Each of the four low pressure core spray pumps (LPCS) at each unit also require ESW flow to cool their internal motor lubricati~~ng~~ oil.

2.1.1 Worst Case Accident

The worst case DBA, analyzed under 10 CFR 50, Appendix K, includes a recirculation system discharge piping break, with a loss of a station battery as the single failure. This would result in:

- The failure of one EDG to start due to loss of DC control power and the loss of one ESW pump powered from that EDG. One low pressure core spray system (LPCS) (two pumps) would be unavailable due to loss of DC control power.

- The three EDGs remaining would supply power to the remaining ESW pump and one LPCS sub-system (two pumps) and three low pressure coolant injection (LPCI) pumps. However, because of the location of the assumed recirculation pipe break two of the three LPCI pumps would pump water out of the break, not to the core. This would leave one LPCS sub-system (two pumps) and one LPCI pump injecting to the core.

Using these initial conditions and assumptions the PBAPS 10 CFR 50, Appendix K analytical analysis determined that adequate core cooling would be maintained.

2.2 Alternate Operation

To allow cooling in the event of a seismic event that damages the Conowingo Dam or in the event of flooding, the ESW pumps operate in conjunction with the ESW booster pumps and the emergency cooling tower (ECT) to cool the ESW loads. In this mode (closed loop), the ECT gravity drains to the isolated ESW/high pressure service water (HPSW) pump structure. The ESW pumps operate to supply the ESW cooling loads. MO-498 is closed to isolate the discharge header from the Conowingo Pond. The ESW booster pumps start automatically upon closure of the MO-498 valve and take a suction from the isolated discharge header. The high point in this flow path is where the ESW piping enters the ECT, approximately 44 feet above the normal ESW flow path high point. An ESW booster pump is necessary to overcome this additional elevation difference to ensure adequate flow to the cooled components and back to the ECT.

3.0 EVENT ANALYSIS

3.1 Event Scenario

The inspectors developed the following sequence of events based on interviews and review of security computer time logs and plant records (the approximate times listed are based on personnel interviews). It is important to note that

the interviews were conducted approximately one-month following the event and some differences in personnel recollections were identified.

August 3, 1994:

The VOTES testing of MO-498 was scheduled.

All EDGs and ECCS equipment at both units were operable.

12:21 p.m. The MO-498 breaker was locked open with the valve open, with a special condition tag hung allowing maintenance to operate the breaker and valve for VOTES testing. Maintenance received the key for the lock on the valve breaker. Once the tagout was established, the operators had no indication or control of the valve position from the control room.

The B ESW booster pump control switch was tagged open to prevent the automatic pump start when MO-498 was closed during VOTES testing. The A ESW booster pump was already inoperable since its suction piping was removed on July 27, 1994, to repair a flawed weld.

6:42 p.m. The work control supervisor (licensed senior reactor operator (SRO)), authorized maintenance to perform the VOTES testing, as documented in the work package.

6:45 p.m. The Unit 2 reactor operator (RO) authorized the maintenance job leader to perform MO-498 VOTES testing, as documented in the work package.

The RO and control room supervisor (CRS) indicated that prior to authorizing this activity, a briefing was conducted to inform the maintenance job leader to monitor the operations radio communications channel and to be prepared to operate MO-498 as directed by operations.

The MO-498 maintenance job leader did not recall the briefing and no written records of the briefing exist.

7:07 p.m. MO-498 preventive maintenance activities and VOTES testing commenced. This required maintenance to unlock the breaker and operate the valve locally from the breaker enclosure, in the E-4 EDG room. With the breaker closed, the operators had position indication and could have operated the valve from the control room if required.

10:22 p.m. The maintenance technicians left MO-498 shut and reopened and locked the breaker when they went to lunch. The maintenance technicians took the key for the breaker lock with them. This removed the position indication and the ability to operate this valve from the control room.

Consequently, the ESW system was left in an unanalyzed condition.

APPROX
10:30 p.m. The on-coming CRS noted that the ECT high level alarm indication was illuminated.

11:09 p.m. The maintenance technicians returned to the location of the MO-498 valve and breaker.

APPROX
11:15 p.m. A security guard notified the control room that water was overflowing the ECT basin.

The CRS contacted the maintenance technicians, informing them of the ECT overflow and the need to open MO-498 to allow ECT pump down.

The CRS initiated a Performance Enhance Program (PEP) review to investigate the causes for the ECT overflow.

The ESW system was returned to an analyzed condition.

September 7, 1994:

During a review of the August 3 ECT overflow event the inspectors identified the possibility that closing MO-498 may have affected the ability of the ESW system to supply its designed cooling flow to the EDG and ECCS room/pump coolers.

The inspectors informed PECO Energy of the ESW operability concern. PECO began an investigation into the August 3 event.

3.2 Event Findings

The inspectors concluded that PECO Energy isolated the ESW system from its normal discharge path for approximately 50 minutes (10:22 p.m. to 11:15 p.m.). This affected the ability of the ESW system to perform its design basis function of cooling the EDGs and ECCS pump/room coolers. This activity was not properly reviewed by numerous station groups (engineering, maintenance planning, and operations). These groups failed to recognize the potential significance of isolating the ESW discharge header on emergency system operability. Consequently, PECO Energy did not perform a safety evaluation, and develop procedures before conducting this activity. Further, PECO Energy failed to recognize the potential ESW operability issues following the ECT overflow event. The inspectors identified the following issues:

- On August 3, MO-498 was closed with its breaker open for approximately 50 minutes, isolating the normal ESW discharge path to the river. This allowed the normal non-safety related SW to flow through the ECCS room/pump coolers and the non-operating B ESW booster pump to the ECT. The only apparent symptom of this configuration problem was the increase in ECT level and eventual overflow.

More significantly, due to the approximate 44 foot elevation difference between the normal ESW discharge piping and the ECT piping, the ESW pumps would not have been able to supply their design flowrates to the EDG and ECCS pump/room coolers. This ESW flowpath was not described in the Updated Final Safety Analysis Report (UFSAR). Therefore, this flowpath constituted a change to the facility as described in the UFSAR. PECO Energy did not perform a safety evaluation as required by 10 CFR 50.59 to ensure that this ESW configuration change did not introduce an unreviewed safety question.

- Engineering and planning did not evaluate the effects of MO-498 VOTES testing on system operability prior to presenting the work to the operations shift.

- The operations shift did not fully realize the effects of the VOTES testing and take appropriate actions to ensure that the ESW system could perform its safety function. Poor communications between the control room operators and the maintenance technicians and poor operator understanding of the testing to be performed on MO-498, resulted in isolation of the ESW system design basis flow path. PECO Energy did not take action to ensure that MO-498 could be re-opened in a timely manner following an accident.

  The inspectors found that the operations department did not provide adequate controls to ensure ESW system operability when the maintenance department had control of MO-498. A written procedure was not developed and PECO Energy did not ensure that an operator was stationed continuously to operate MO-498. The operations department turned over control of the valve to maintenance. The maintenance technicians closed the valve and locked open the breaker, taking the key with them on their lunch break. By not establishing procedural controls, PECO Energy was unknowingly dependent upon operators recognizing that MO-498 was closed and taking actions to contact the maintenance technicians to open MO-498 and restore the ESW system to an analyzed condition. This was significant given the importance of the MO-498 valve and the nature of the maintenance activity (VOTES testing) where the component had the potential to be left closed for an extended time.

  PECO Energy PBAPS Technical Specification Interpretation #61 states that a system may be operable if reasonable manual operator actions can be performed to return it to service in an emergency. These actions must be specified by an approved procedure and operator cognizance must be continuously maintained. This position, consistent with NRC Inspection Manual Procedure 9900, "Technical Guidance" on operability, was not implemented in the control of MO-498.

- The ESW system was required to support operation of the EDGs and the ECCS pump/room coolers. Since ESW was placed in an unanalyzed condition and reasonable manual operator actions were not specified in an approved procedure the operability of all station EDGs and ECCS components could not be assured without prior additional engineering analysis. This

condition is not allowed by the Technical Specifications (TS) and would have required a shutdown within six hours per TS 3.0.C. PECO Energy failed to recognize these operability issues and did not enter TS 3.0.C.

- PECO Energy's PEP review of the August 3, ECT overflow event was inadequate because it did not identify any operability concerns. The PEP stated that if an EDG had started, the ECT overflow would have been worse, due to the increased flow. PECO management and engineering personnel reviewed the PEP, focusing solely on the reasons for the ECT overflow, and did not identify the ESW operability concerns.

4.0 SUBSEQUENT PECO ANALYSIS OF THE EVENT

4.1 Engineering Analysis

After the inspectors identified the operability concerns, PECO Energy conducted an engineering analysis to determine the affects of the additional 44 feet of system head on ESW system flow and the affects of the reduced flow on the operability of cooled systems. This analysis conservatively assumed that a DBA LOCA occurred with MO-498 shut and that operators took no actions to restore the ESW system or reduce EDG loads. Cooling flow requirements were further reduced from the design flows based on the August 3, 1994, inlet temperature being approximately nine degrees cooler than the design basis river temperature. PECO Energy reached the following preliminary conclusions:

- ESW system flowrate would have been reduced by approximately fifty percent from their design flowrates, due to the added elevation of flow to the ECT.

- Adequate cooling would have been provided to all ECCS pump and room coolers.

- The EDGs would have remained operable for the first ten minutes of a DBA, based on conditions on August 3, 1994, and on the inherent heat-up time following a start.

- Some EDG failures would occur from 16 minutes to one hour after a DBA without operator action to redistribute EDG electrical loading.

The inspector determined that these preliminary input assumptions and analytical results appeared reasonable; however, further review of the affects of the MO-498 being closed on the operability of the EDGs and ECCS equipment is pending completion of PECO Energy's final engineering analysis.

4.2 Corrective Actions

After the inspectors identified the operability concerns, PECO Energy implemented an extensive root cause(s) investigation to determine the necessary corrective actions to prevent recurrence. PECO Energy's investigation was broadly focused on the entire work control process. As an interim measure, PECO Energy issued written guidance to the operators that

valves should be declared inoperable during VOTES testing. The inspectors determined that this guidance was adequate to prevent a similar occurrence, and will review PECO Energy's final corrective actions when complete.

5.0 CONCLUSION

The inspectors concluded that the overall safety consequence of this event was small since no conditions occurred that required the use of the EDGs and ECCS equipment, during the time that valve MO-498 was shut; however, the failure of the plant staff to ensure an adequate review of this situation, initially and afterward, represented a significant degradation in plant safety. The lower than design ESW flows could have unknowingly affected the operability of the EDGs and ECCS equipment. The effect could have been to place both units in an unanalyzed condition for assumed EDG and ECCS availability with respect to the worst case DBA analysis discussed in section 2.2.1.

The inspectors identified three apparent violations which are being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedure for Enforcement Actions" (Enforcement Policy), 10 CFR Part 2, Appendix C. Specifically:

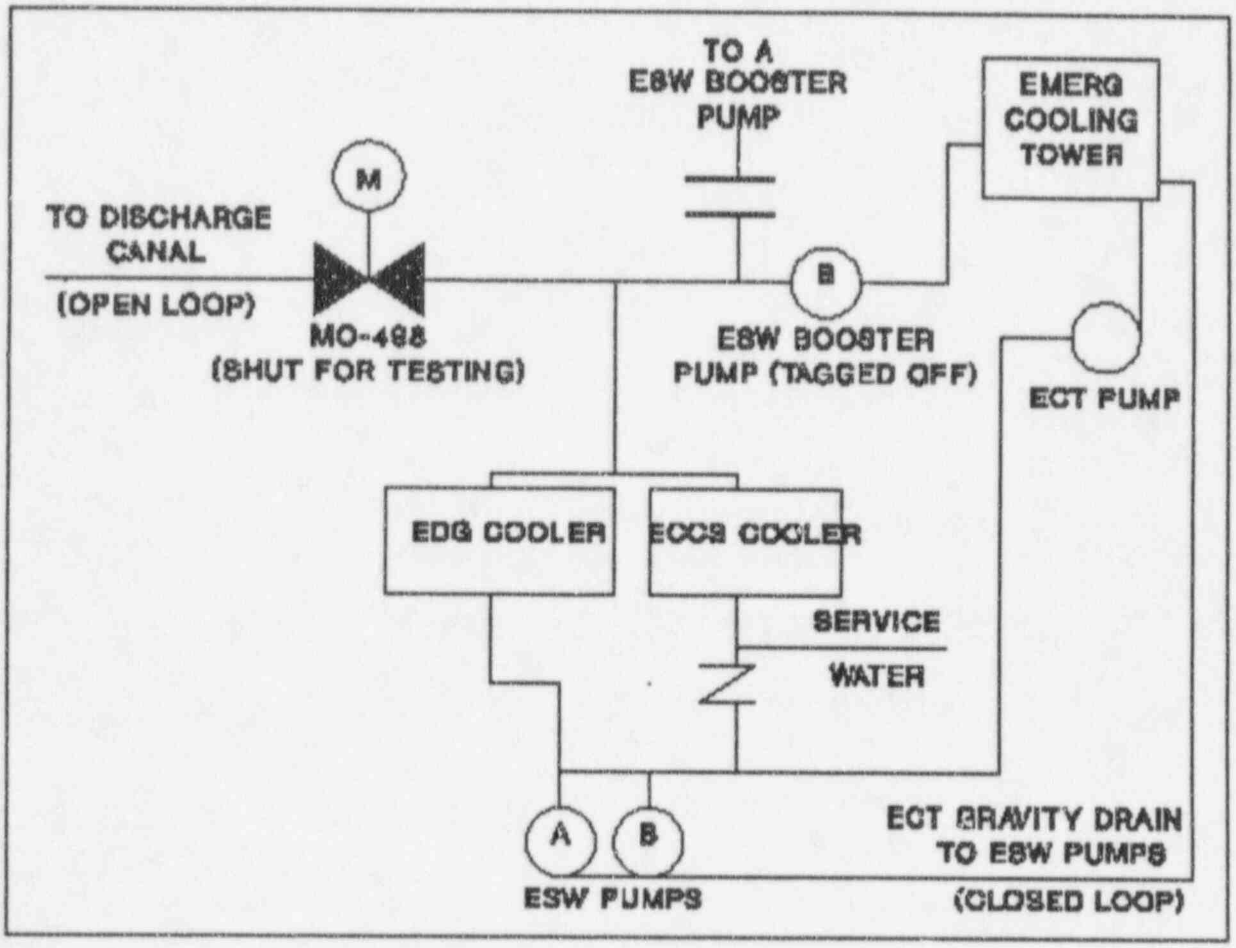
- PECO Energy conducted the maintenance activity on valve MO-498 without completing a safety review to determine that it did not represent an unreviewed safety question. 10 CFR 50.59 required that PECO Energy perform a written safety evaluation prior to making a facility change to ensure it did not involve an unreviewed safety question. Contrary to the above, PECO Energy did not perform an analysis prior to making this change. This is an apparent violation of 10 CFR 50.59.

- Procedures were not in place to ensure that the ESW system would be able to perform its design function in the event of an accident. Procedures specifying that MO-498 needed to be opened in the event of an accident were not in place prior to the maintenance activity. This was significant given the importance of the MO-498 valve and the nature of the maintenance activity (VOTES testing) where the component had the potential to be left closed for an extended time. This was in apparent violation of 10 CFR 50, Appendix B, Criterion III, Design Controls.

- PECO energy did not identify that closing MO-498 altered the emergency service water system flow path and thus affected the flow rates to safety-related components, during their initial PEP review. The PECO Energy staff focused on the emergency cooling tower overflowing, not on any potential safety effects of the closure of MO-498. This represented an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions.

ATTACHMENT I

ESW FLOW DIAGRAM



UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

November 21, 1994

EA 94-197

Mr. D. M. Smith
Senior Vice President - Nuclear
PECO Energy Company
Nuclear Group Headquarters
Correspondence Control Desk
Post Office Box 195
Wayne, Pennsylvania 19087-0195

SUBJECT: NOTICE OF VIOLATION AND PROPOSED IMPOSITION OF CIVIL PENALTY - $87,500
(NRC Combined Inspection Report Nos. 50-277/94-24 and 50-278/94-24)

Dear Mr. Smith:

This refers to the NRC inspection conducted on September 7-14, 1994, at the Peach Bottom Atomic Power Station in Delta, Pennsylvania. This inspection included an examination of the circumstances surrounding the August 3, 1994, isolation of the emergency service water (ESW) system normal return to the ultimate heat sink. The report documenting this inspection was sent to you on September 29, 1994, and violations of NRC requirements were identified. On October 18, 1994, an enforcement conference was conducted with you and other members of your staff to discuss the violations, their causes, and your corrective actions.

On August 3, 1994, your staff had unknowingly placed the ESW system in an unanalyzed configuration that prevented safety-related equipment from receiving cooling water at the design flow rate. Specifically, maintenance personnel shut, de-energized, and left MO-498, the ESW system discharge valve to the Susquehanna River, unattended for approximately 50 minutes during valve testing. This action, which resulted in the normal ESW system return flow to the river being isolated and return flow being directed to the emergency cooling tower (ECT), was due to inadequate communications between the maintenance and operations staff and a weak procedure regarding positive control of the valve's position.

The valve was closed in accordance with a test procedure which required that thrust data be obtained while the valve was stroked. With the normal ESW system discharge to the Susquehanna river isolated, system flow would have been discharged to the ECT if the ESW system had been called upon to operate in the event of an accident. In this condition, ESW system flow to the emergency diesel generators (EDGs) and the emergency core cooling systems (ECCSs) room coolers would have been reduced because of the addition of approximately 44 feet of static head, in addition to increased dynamic head losses because ESW system flow would be directed through the non-operating ESW system booster pumps. Your analysis of the condition later determined that this reduced flow would have prevented the EDGs from performing their safety-related functions had the design basis accident occurred with river water at the maximum design temperature of 90°F.

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This condition occurred because procedures were not in place that required maintenance personnel to remain at the valve throughout the testing so as to immediately open the valve if it were needed. In this case, after maintenance personnel received work start authorization, they closed the valve and subsequently left it unattended and in the closed position for approximately 50 minutes. The valve was not reopened until after a control room ECT alarm and subsequent ECT overflow due to regular service water flowing through the alternate path and to the ECT. Although the valve was immediately reopened at that time, your staff did not recognize the impact of this condition on the ESW system operability. That impact was not identified until the event was reviewed by the NRC resident inspectors on September 7, 1994, at which time the NRC special inspection was initiated and the degradation and related violations were identified. A second cause of this event was that there was an inadequate review of the valve testing procedure performed to ensure that the ESW system would be maintained within its design basis while in the test configuration. As a result, the procedure, which required that MO-498 be closed for a period of time such that test data could be collected, had not considered the effect on system operability with the normal discharge path to the ultimate heat sink isolated.

The NRC recognizes that your subsequent evaluation of the condition revealed that the ESW system would have provided adequate post-accident short term cooling of the EDGs and ECCS, considering the value of actual plant parameters at the time the subject valve was closed. In addition, an ECT overflow condition and/or high EDG temperatures would have possibly alerted operators that the ESW system was improperly aligned and long term cooling could have been restored once the valve was reopened. Nonetheless, the failure to establish appropriate procedural controls to ensure positive control of MO-498, if called upon to function in the event of an accident, and the failure to perform an adequate review of the valve testing procedure in order to maintain the design basis, represent significant regulatory concerns and violations of NRC requirements. These concerns are significant since closure of the valve resulted in a reduction of the ESW system cooling capacity, because of lower than designed system flow rates. Further, the reduction in the ESW system cooling capacity resulted in an unanalyzed degradation of EDG and ECCS system operability. In addition, the unattended closed valve could have substantially complicated a response to an accident or significant transient. Therefore, the violations have been categorized as a single Severity Level III problem in accordance with the "General Statement of Policy and Procedures for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (Enforcement Policy).

The NRC is concerned because there were, at minimum, two opportunities for your staff to have prevented this event from occurring. The first opportunity consisted of a reactor operator (RO) expressing concern over shutting MO-498, but was subsequently assured by a Senior Reactor Operator that personnel would be stationed at the valve to immediately return it to an open position if the flow path was needed. The second opportunity occurred when the pre-testing briefing was performed. This briefing, conducted between control room operators and the testing crew, was not performed with the crew that actually tested MO-498; rather, the briefing was mistakenly conducted with another testing crew that was performing valve testing on other valves in another area of the station. Thus, the control room staff was not able to adequately communicate the scope of the

testing, and the importance to safety of the position of MO-498, and the staff failed to exhibit the appropriate sensitivity to the control of work, as evidenced by the wrong crew being briefed. This example of poor communications between operations and maintenance crews contributed directly to the failure to maintain positive control of MO-498 and ultimately resulted in placing the ESW system in its unanalyzed condition.

The NRC recognizes that subsequent to the identification of the violations, corrective actions were taken or planned, to prevent the violations and preclude recurrence, including (1) short-term actions such as review of the event with all maintenance personnel, and review of expectations for equipment manipulation with all operations and maintenance personnel; and (2) long-term actions which included (a) addition of enhanced controls to the related testing procedure; (b) review of other work processes to ensure adequate controls exist; (c) review of expectations with the work planners concerning improved planning and coordination activities; (d) reorganization of the operations services group to improve work planning; and (e) enhancement of procedures covering release of equipment for maintenance to provide clear guidance regarding equipment operability and control requirements.

Notwithstanding those corrective actions, to emphasize the importance of (1) appropriate coordination between operations and maintenance personnel, (2) establishment of appropriate procedural controls during the conduct of maintenance activities, to ensure that safety equipment is appropriately maintained, and (3) operations maintaining control of such evolutions rather than deferring this responsibility to maintenance, I have been authorized, after consultation with the Director, Office of Enforcement, to issue the enclosed Notice of Violation and Proposed Imposition of Civil Penalty (Notice) in the amount of $87,500 for the violations set forth in the enclosed Notice.

The base civil penalty amount for a Severity Level III problem is $50,000. The escalation and mitigation factors set forth in the enforcement policy were considered, and on balance, 75% escalation of the civil penalty is warranted. Under the factor of identification, 50% escalation is warranted because the problem was identified by the NRC. Because of the self-disclosing nature of the event, your staff identified the mispositioning of the ESW system valve on August 3, 1994; however, you did not recognize the impact of the closed valve on the operability of the ESW system. Your corrective actions were considered comprehensive and 25% mitigation on this factor is warranted; full 50% mitigation is not appropriate because at the time of the enforcement conference, a timetable had not been established for completion of the long term corrective actions. With respect to your past performance, although there have been no related violations in this area in the past two years, your overall enforcement history includes a Severity Level III violation in the area of radiation protection and your SALP ratings in the area of maintenance and engineering were both Category 2. For these reasons, full mitigation on this factor is not warranted; rather, 50% mitigation is considered appropriate. With respect to the "prior opportunity to identify" factor, you did not identify the impact that closing MO-498 had on the ESW system, despite having several prior opportunities to have identified the problem prior to NRC's identification on September 7, 1994. These prior opportunities included the technical review of the testing procedure that required MO 498 to be shut, which subsequently placed the ESW system in an

unanalyzed condition, and the issuance of a corrective action document following the ECT overflow that focused only on the overflow event and failed to probe deeper into the more significant issue of the ESW system being in an unanalyzed condition. Also, the problem could have been identified prior to MO-498 being shut when the RO voiced concerns about the manipulation. The NRC has determined that you clearly had an opportunity for discovering that the ESW system was outside of its design basis, but you did not do so; therefore, 100% escalation of this factor is warranted. The other factors were considered and no further adjustment was deemed appropriate. Therefore, the final adjusted civil penalty is $87,500.

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. In your response, you should document the specific actions taken and the additional actions you plan to prevent recurrence. To the extent appropriate, you may reference any prior submittal in your response.

In addition, another event occurred at the station in October 1994, involving the failure to properly monitor reactor temperature during restoration from a plant pressure test of the reactor coolant system. This event indicates similar problems with control of plant conditions. Although the consequence to safety of the October event was low, it provides another example of performance deficiencies in shift management's command and control of evolutions, use of procedures, and operator monitoring of changing plant conditions. Therefore, you should formulate corrective actions to address these weaknesses and the deficiencies identified in the enclosed Notice.

After reviewing your response to this Notice, including your proposed corrective actions and the results of future inspections, the NRC will determine whether further NRC enforcement action is necessary to ensure compliance with NRC regulatory requirements.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response will be placed in the NRC Public Document Room (PDR). To the extent possible, your response should not include any personal privacy, proprietary, or safeguards information so that it can be placed in the PDR without redaction. However, if you find it necessary to include such information, you should clearly indicate the specific information that you desire not to be placed in the PDR, and provide the legal basis to support your request for withholding the information from the public.

The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96-511.

Sincerely,

Thomas T. Martin
Regional Administrator

Docket Nos. 50-277/50-278
License Nos. DPR-44/DPR-56

Inclosure: Notice of Violation and Proposed Imposition of Civil Penalty

cc w/encl:
J. Doering, Chairman, Nuclear Review Board
G. Raine, Vice President, Peach Bottom Atomic Power Station
W. Smith, III, Vice President, Nuclear Station Support
D. Fetters, Director, Nuclear Engineering
A. Kirby, III, External Operations - Nuclear, Delmarva Power & Light Co.
G. Edwards, Plant Manager, Peach Bottom Atomic Power Station
A. Wasong, Manager, Experience Assessment
G. Hunger, Jr., Director, Licensing
J. Durham, Sr., Senior Vice President and General Counsel
J. Isabella, Director, Generation Projects Department, Atlantic Electric
B. Gorman, Manager, External Affairs
R. McLean, Power Plant Siting, Nuclear Evaluations
D. Poulsen, Secretary of Harford County Council
R. Ochs, Maryland Safe Energy Coalition
J. Walter, Chief Engineer, Public Service Commission of Maryland
PUBLIC
Nuclear Safety Information Center (NSIC)
K. Abraham, PAO-RI (2)
NRC Resident Inspector
Commonwealth of Pennsylvania
TMI - Alert (TMIA)

Mr. D. Smith

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ENCLOSURE

NOTICE OF VIOLATION
AND
PROPOSED IMPOSITION OF CIVIL PENALTY

PECO Energy Company
Peach Bottom Units 2 and 3
Delta, Pennsylvania

Docket Nos. 50-277, 50-278
License Nos. DPR-44, DPR-56
EA 94-197

During an NRC inspection conducted on September 7-14, 1994, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C, the Nuclear Regulatory Commission proposes to impose a civil penalty pursuant to Section 234 of the Atomic Energy Act of 1954, as amended (Act), 42 U.S.C. 2282, and 10 CFR 2.205. The particular violations and associated civil penalty are set forth below:

A. 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into procedures and instructions.

Contrary to the above, on August 3, 1994, the licensee conducted a testing activity on the emergency service water (ESW) system that placed the system in a configuration that was not within the design basis described in the Updated Safety Analysis Report. Specifically, ESW system valve MO-498, the system's normal return to the ultimate heat sink (UHS), was shut and left unattended. As a result, the ESW system flow to safety-related components was reduced to the extent that adequate cooling was not available in the event that the design basis accident occurred at the design basis UHS maximum temperature. (01013)

B. 10 CFR Part 50, Appendix B, Criterion V, requires, in part, that activities affecting quality shall be prescribed by documented instructions and procedures of a type appropriate to the circumstances and shall be accomplished in accordance with those procedures and instructions.

Contrary to the above, on August 3, 1994, the licensee tested ESW System Valve MO 498, an activity affecting quality, in a manner that was not prescribed by documented instructions and procedures of a type appropriate to the circumstances. Valve MO-498, the ESW system normal return to the ultimate heat sink and important to maintaining adequate cooling water flow to safety related components, was shut and procedures were not in place to require personnel to remain at the valve and immediately open the valve if needed in the event of an accident. As a result of the inadequate procedure, after shutting the valve, maintenance personnel left the valve unattended and in the shut position for approximately 50 minutes. (01023)

This is a Severity Level III problem (Supplement I).
Civil Penalty - $87,500.

Pursuant to the provisions of 10 CFR 2.201, PECO Energy Company (Licensee) is hereby required to submit a written statement or explanation to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, within 30 days of the date of this Notice of Violation and Proposed Imposition of Civil Penalty (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation" and should include for each alleged violation: (1) admission or denial of the alleged violation, (2) the reasons for the violations if admitted, and if denied, the reasons why, (3) the corrective steps that have been taken and the results achieved, (4) the corrective steps that will be taken to avoid further violations, and (5) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in this Notice, an Order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked or why such other action as may be proper should not be taken. Consideration may be given to extending the response time for good cause shown. Under the authority of Section 182 of the Act, 42 U.S.C. 2232, this response shall be submitted under oath or affirmation.

Within the same time as provided for the response required above under 10 CFR 2.201, the Licensee may pay the civil penalty by letter addressed to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, with a check, draft, money order, or electronic transfer payable to the Treasurer of the United States in the amount of the civil penalty proposed above, or may protest imposition of the civil penalty in whole or in part, by a written answer addressed to the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission. Should the Licensee fail to answer within the time specified, an order imposing the civil penalty will be issued. Should the Licensee elect to file an answer in accordance with 10 CFR 2.205 protesting the civil penalty, in whole or in part, such answer should be clearly marked as an "Answer to a Notice of Violation" and may: (1) deny the violations listed in this Notice, in whole or in part, (2) demonstrate extenuating circumstances, (3) show error in this Notice, or (4) show other reasons why the penalty should not be imposed. In addition to protesting the civil penalty in whole or in part, such answer may request remission or mitigation of the penalty.

In requesting mitigation of the proposed penalty, the factors addressed in Section VI.B.2 of 10 CFR Part 2, Appendix C, should be addressed. Any written answer in accordance with 10 CFR 2.205 should be set forth separately from the statement or explanation in reply pursuant to 10 CFR 2.201, but may incorporate parts of the 10 CFR 2.201 reply by specific reference (e.g., citing page and paragraph numbers) to avoid repetition. The attention of the Licensee is directed to the other provisions of 10 CFR 2.205, regarding the procedure for imposing a civil penalty.

Upon failure to pay any civil penalty due which subsequently has been determined in accordance with the applicable provisions of 10 CFR 2.205, this matter may be referred to the Attorney General, and the penalty, unless compromised, remitted, or mitigated, may be collected by civil action pursuant to Section 234c of the Act, 42 U.S.C. 2282(c).

The response noted above (Reply to Notice of Violation, letter with payment of civil penalty, and Answer to a Notice of Violation) should be addressed to: Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555 with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region I, 475 Allendale Road, King of Prussia, Pennsylvania 19406 and a copy to the Senior Resident Inspector, Peach Bottom Station.

Dated at King of Prussia, Pennsylvania
this 21st day of November 1994

PRIORITY 2

(NUDOCS OFFSITE FACILITY)

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AUTH.NAME AUTHOR AFFILIATION
HUNGER,G.A. PECO Energy Co., (formerly Philadelphia Electric Co.)
RECIP.NAME RECIPIENT AFFILIATION
LIEBERMAN,J. Ofc of Enforcement (Post 870413)

SUBJECT: Responds to violation & proposed imposition of civil penalty in amount of $87,500.

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	DEDRO	1	1	NRR/DOEA/OEAB11	1	1
	NRR/PMAS/IRCB	1	1	NUDOCS-ABSTRACT	1	1
	OE DIR	1	1	OE FILE 01	1	1
	RGN1 FILE 03	1	1			
EXTERNAL:	LITCO BRYCE,J H	1	1	NOAC	1	1
	NRC PDR	1	1			
NOTES:		1	1			

P R I O R I T Y 2 D O C U M E N T

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Station Support Department

DCS

PECO ENERGY

PECO Energy Company
Nuclear Group Headquarters
965 Chesterbrook Boulevard
Wayne, PA 19087-5691

December 21, 1994

Docket Nos. 50-277
50-278
License Nos. DPR-44
DPR-56

Mr. James Lieberman
Director, Office of Enforcement
U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Subject: Peach Bottom Atomic Power Station, Units 2 and 3
Remittance of Civil Monetary Penalty

Dear Mr. Lieberman:

This letter is being submitted in response to an NRC letter dated November 21, 1994, issuing a Notice of Violation and proposed imposition of civil penalty in the amount of $87,500 for violations of NRC regulations as set forth in 10CFR50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." We are remitting the enclosed check in the amount of $87,500 for payment of the cited civil penalty.

If you have any questions or require additional information, please do not hesitate to contact us.

Very truly yours,

G. A. Hunger, Jr.

G. A. Hunger, Jr.
Director - Licensing

Enclosure

cc: T. T. Martin, Administrator, Region I, USNRC (w/o enclosure)
W. L. Schmidt, USNRC Senior Resident Inspector, PBAPS (w/o enclosure)
R. R. Janati, Commonwealth of Pennsylvania (w/o enclosure)

Rec'd w/check
12/23/94

IE14
1/0

280015

Dickinson M. Smith
Senior Vice President and
Chief Nuclear Officer

PECO ENERGY

PECO Energy Company
Nuclear Generation Group
965 Chesterbrook Blvd., 63C-3
Wayne, PA 19087-5691
610 640 6600
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10CFR 2.201
10CFR 2.205

December 21, 1994

Docket Nos. 50-277
50-278
License Nos. DPR-44
DPR-56

Director, Office of Enforcement
U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Subject: Peach Bottom Atomic Power Station Units 2 & 3
Reply to Notice of Violation and Proposed Imposition of a Civil Penalty NRC Inspection Report Nos. 50-277/94-24; 50-278/94-24

Gentlemen:

In response to your letter dated November 21, 1994, which transmitted the Notice of Violation (NOV) and Proposed Civil Penalty, PECO Energy Company submits the attached reply. The NOV was identified in a special safety inspection (94-24/24) that evaluated activities performed August 3, 1994, that placed the Emergency Service Water (ESW) system in an unanalyzed configuration for approximately 50 minutes.

A check in payment of the civil penalty made payable to the Treasurer of the United States was transmitted separately by PECO Energy letter to the Director, Office of Enforcement dated December 21, 1994.

If you have any questions or desire further information, please do not hesitate to contact us.

Dm Smith

270077

JE14 1/1

Attachment and Affidavit

cc: R. A. Burricelli, Public Service Electric & Gas
R. R. Janati, Commonwealth of Pennsylvania
T. T. Martin, USNRC, Administrator, Region I
W. L. Schmidt, USNRC, Senior Resident Inspector
H. C. Schwemm, VP - Atlantic Electric
R. I. McLean, State of Maryland
A. F. Kirby III, DelMarVa Power

COMMONWEALTH OF PENNSYLVANIA :

: ss.

COUNTY OF CHESTER :

D. M. Smith, being first duly sworn, deposes and says:

That he is Senior Vice President and Chief Nuclear Officer of PECO Energy Company; that he has read the attached reply to Notice of Violation and Proposed Imposition of a Civil Penalty NRC Inspection Report No. 94-24, for Peach Bottom Atomic Power Station Facility Operating Licenses DPR-44 and DPR-56 and knows the contents thereof; and that the statements and matters set forth therein are true and correct to the best of his knowledge, information and belief.

D M Smith

Senior Vice President and
Chief Nuclear Officer

Subscribed and sworn to
before me this 21st day
of December 1994.

Erica A. Santori

Notary Public

Notarial Seal
Erica A. Santori, Notary Public
Tredyffrin Twp., Chester County
My Commission Expires July 10, 1995

RESPONSE TO NOTICE OF VIOLATION 94-24-01

Restatement of the Violation

A. 10 CFR 50, Appendix B, Criterion III, requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into procedures and instructions.

Contrary to the above, on August 3, 1994, the licensee conducted a testing activity on the emergency service water (ESW) system that placed the system in a configuration that was not within the design basis described in the Updated Safety Analysis Report. Specifically, ESW system valve MO-498, the system's normal return to the ultimate heat sink (UHS), was shut and left unattended. As a result, the ESW system flow to safety-related components was reduced to the extent that adequate cooling was not available in the event that the design basis accident occurred at the design basis UHS maximum temperature. (01013)

B. 10 CFR Part 50, Appendix B, Criterion V, requires, in part, that activities affecting quality shall be prescribed by documented instructions and procedures of a type appropriate to the circumstances and shall be accomplished in accordance with those procedures and instructions.

Contrary to the above, on August 3, 1994, the licensee tested ESW System Valve MO-498, an activity affecting quality, in a manner that was not prescribed by documented instructions and procedures of a type appropriate to the circumstances. Valve MO-498, the ESW system normal return to the ultimate heat sink and important to maintaining adequate cooling water flow to safety-related components, was shut and procedures were not in place to require personnel to remain at the valve and immediately open the valve if needed in the event of an accident. As a result of the inadequate procedure, after shutting the valve, maintenance personnel left the valve unattended and in the shut position for approximately 50 minutes. (01023)

This is a Severity Level III problem (Supplement I).

Admission or Denial of Alleged Violation

The PECO Energy Company acknowledges the violation.

Background

On August 3, 1994, at approximately 12:21 PM a clearance was applied to Motor Operated Valve MO-0-33-498 to allow diagnostic testing of the valve. This valve controls ESW discharge flow to the Susquehanna River. Testing was performed in accordance with Maintenance Procedure M-511-130, "Procedure for Diagnostic Testing of Limitorque Motor Operated Valves using Liberty Technologies 'Votes' Method." This procedure dealt with the mechanics of performing the test and did not address system operability issues that could arise.

The MO-498 breaker was blocked and locked in the open condition. A Special Condition Tag was hung on the breaker to allow Maintenance technicians to operate the breaker and the valve during the VOTES test. Maintenance technicians received the key to unlock the breaker as part of the clearance. With the valve breaker in the open position, control room indication of valve position became unavailable.

At 6:27 PM two Maintenance technicians entered the Control Room to obtain permission to begin VOTES testing of another ESW valve, MO-0-33-841, the Emergency Cooling Water Pump Discharge Valve. Approximately 10 minutes later, two other Maintenance technicians entered the Control Room to obtain permission to VOTES test MO-498. While both groups were in the Control Room they each received permission to begin testing from the Work Control Supervisor. In addition, the MO-498 work crew received permission to begin work from the Unit 2 Reactor Operator.

The Unit 2 Reactor Operator had reservations about allowing work to be done on MO-498 and expressed his concerns to the Control Room Shift Supervisor. The Control Room Shift Supervisor addressed these concerns by questioning one of the Maintenance technicians who he thought was working on MO-498. Through this questioning he confirmed that the testing would not mechanically disable the valve, that the valve would be immediately available to the operator if needed, and that the technicians had a radio so that they could be immediately contacted by the Control Room. Satisfied that operators would be able to take control of the valve immediately if necessary, the Control Room Shift Supervisor informed the Unit 2 Reactor operator that valve testing was permissible. In reality, however, the Control Room Shift Supervisor had questioned the lead technician working on MO-841.

At approximately 7:07 PM testing began on MO-498. The testing required the Maintenance technicians to close the valve breaker and operate the valve locally from its breaker in the E-4 diesel bay. During this testing the Maintenance technicians did not notify the Control Room when the valve's position was changed. They believed that the operator signoff in their test procedure which granted permission to perform VOTES testing also constituted the operator's permission to change valve position as needed without prior control room notification.

At 10:22 PM the Maintenance technicians temporarily stopped work and left the work area. At that time, they left MO-498 in the closed position, reopened the valve breaker and locked it. The key for the valve breaker lock remained with the Maintenance technicians who did not notify the Control Room operators that they had left the valve area or that the valve was in the closed position. With MO-498 closed, service water which is normally supplied to ECCS cooling loads was discharged to the Emergency Cooling Tower instead of the river. The technicians believed that they were leaving the valve in a safe condition. The work package did not provide any information on a preferred valve position nor did it prohibit the valve from being left unattended.

Sometime after MO-498 was closed the emergency cooling tower high/low level alarm was received in the Control Room. Operators confirmed that tower level was high using a control room level indicator. They attributed the level increase to rain. Per the alarm response card, the appropriate action was to reduce tower level using the Emergency Cooling Water pump and MO-841. Typically this condition does not require an immediate response and with MO-841 under test, an immediate pump down of the tower was not undertaken.

At 11:09 PM the Maintenance technicians returned to MO-498. At about the same time, the afternoon and night shift Unit 2 Reactor Operators had completed their turnover and the oncoming Reactor Operator began to think about possible reasons for the emergency cooling tower high level alarm. He was skeptical that the alarm was caused by rain. At 11:15 PM just before the Reactor Operator recognized the connection between the emergency cooling tower high level alarm and the work on MO-498, a security guard notified the Control Room that water was overflowing the Emergency Cooling Tower basin. The Reactor Operator immediately informed the Control Room Shift Supervisor that the overflow was probably caused by the work on MO-498.

The Control Room Shift Supervisor contacted the Maintenance technicians informing them of the Emergency Cooling Tower overflow and the need to open MO-498 and MO-841 to allow the cooling tower to drain down. The two valves were opened and the restoration of the cooling tower level to normal was completed. Once the MO-498 was stroked to the open position, the ESW system was returned to an analyzed condition.

Following identification of this problem by the NRC, calculations by PECO Engineering determined that ESW flow would have been reduced by approximately 40%. Additional calculations were performed using this reduced flow rate to determine the operability of emergency diesel generators and ECCS equipment assuming the worst case plant licensing event, a loss of coolant accident with a loss of offsite power. These calculations showed that with the river and air temperatures that existed on the day of the event, all ECCS room coolers and equipment coolers would have performed their design function throughout the event. In addition, the required number of emergency diesel generators would have remained operable during the first ten minutes without operator action. The diesels would have remained operable following the first ten minutes if diesel loads were balanced to below their continuous rating of 2600 kw. Analysis also showed, however, that the reduced ESW flow would have prevented the diesels from performing their safety function had the design basis accident occurred with river water at its design maximum temperature of 90 degrees F. Actual river temperature on the day of the event was 81 degrees F.

Reason for the Violation

Administrative controls to ensure that MO-498 would remain operable during VOTES testing were not clearly established as part of the planning for this activity. Likewise the impact of closing MO-498 on emergency cooling tower level and the ESW system were not addressed in the work package. Continued operability of MO-498 during VOTES testing came to depend solely on the controls the Operators put in place at the start of the job. The challenges encountered during this event could have been avoided had adequate planning taken place before the work request reached the Control Room.

During the planning process it was decided that MO-498 could remain operable during VOTES testing, however, the operability impact associated with this decision was not carefully evaluated or managed. Enhanced work controls to limit the chance of an undetected inoperable condition should have been written into the work package to supplement any verbal controls imposed by Operations. Although written instructions had been successfully used in the past to control work activities, an expectation that such instructions be consistently included in work packages involving operable safety related equipment had not been established. As a result, no one was responsible to verify that it was included in the work package and the absence of enhanced guidance and control was not questioned.

Diagnostic MOV testing had been conducted for several years with no adverse consequences. As a result, VOTES testing was perceived to be a low risk operation with little cause for concern. This perception caused some personnel to be less sensitive to the potential for a problem during the testing of MO-498. Personnel interviewed had a very general understanding of the VOTES testing

process and thought the process simply involved the momentary stroking of a valve to obtain test data from installed sensors. There were no previous problems that would have caused this concept of VOTES testing to be questioned or compelling reasons to research the actual details of the testing procedure. This lack of knowledge about the details of the VOTES test reduced the likelihood that personnel who understood the design and operation of the ESW system would foresee the impact on Emergency Cooling Tower level and restrict the time that the valve could be left closed. Such a restriction may have prevented the maintenance technicians from leaving the valve in the closed position.

Extensive reviews had been previously conducted to determine if equipment operability could be maintained during testing. Tests where equipment could remain operable were reviewed to ensure that appropriate controls were established and written into procedures. This review was restricted to surveillance and routine testing. VOTES testing is a preventative maintenance task which does not fall into either category, therefore it was never thoroughly evaluated.

The request to conduct VOTES testing on MO-498 should have initiated the imposition of enhanced test controls and increased monitoring of the condition of the valve by Operations. Several opportunities to establish these controls existed, but were not effectively achieved. The first opportunity came when Maintenance requested permission from the work control supervisor to initiate work. The work control supervisor recalled being concerned about simultaneous work on MO-498 and MO-841, but did not establish any special controls. Secondly, concern was expressed by the Unit 2 Reactor Operator when he was asked to grant permission to allow testing on MO-498. His concerns were directed to the Control Room Shift Supervisor who resolved the concerns to their mutual satisfaction. Although these individuals recognized that MO-498 was a safety significant valve, the degree of monitoring and control established over the testing of MO-498 was inadequate in view of its safety significance.

The Control Room Shift Supervisor tried to affirm the acceptability of working on the MO-498 valve by questioning one of the maintenance technicians who was in the Control Room seeking permission to perform VOTES testing. The technician questioned, however, was actually working on MO-841. The questions asked by the Shift Supervisor were appropriate, but were general in nature so that neither party realized that they were talking about different valves. As a result, the Maintenance Technicians working on MO-498 never heard the Shift Supervisor's questions and had no awareness of the RO's concerns.

Interaction between the Maintenance Crew and Control Room Operators during MO-498 testing was less than adequate. The Clearance and Tagging Manual requires that Shift Management permission be obtained immediately prior to each Special Condition Tag (SCT) component manipulation. However, the manual also provides an exception to this requirement stating that at the discretion of Shift Management, permission may extend through a series of manipulations not to exceed the shift of the individual granting the permission. During the event the Maintenance technicians did not notify Shift Management immediately prior to each manipulation of the valve. The technicians interpreted the Work Control Supervisor signoff in their test procedure granting permission to perform the test as also granting the exemption from making the notifications. In the mind of the Maintenance Technician, the permission to conduct VOTES testing automatically included permission to stroke the valve and apply the exception for SCT component manipulation notification. Previous experience and the absence of any contrary direction from Operations validated these assumptions.

When the Maintenance technicians left the work area, they left MO-498 in the closed, deenergized position thinking that this was a safe configuration that did not adversely impact plant safety. They did not understand the function of the valve in relation to the ESW system and therefore made an incorrect decision. Had the technicians been clearly informed of the function of the valve and its safety significance by a pre-job briefing, this event may have been averted. This information, however, was not provided to the technicians before they went to the Control Room to get permission to initiate testing. It also was not provided by any of the Operations personnel who had contact with the technicians.

Corrective Steps That Have Been Taken and The Results Achieved

A Performance Enhancement Program (PEP) investigation (PEP-I0002629) was initiated September 7, 1994, to determine the causal factors of placing the ESW system in an unanalyzed configuration and to develop appropriate corrective actions to prevent recurrence.

Appropriate counselling and disciplinary actions were administered commensurate with individual's level of responsibility.

This event was reviewed with Maintenance and Operations and Planning personnel.

Required reading packages were developed and communicated to Operations personnel on September 12 & 13, 1994. Operations personnel were instructed to consider Motor Operated Valves inoperable during VOTES testing and were given specific instruction to consider systems inoperable with components being worked under action requests, minor maintenance, SCT, or "Fix it Now" (FIN) team work unless otherwise determined by a licensed operator.

MO-498 was information tagged indicating that it shall only be operated using PORC approved procedures that specifically address MO-498. The VOTES test procedure is an example of a procedure that does not meet this criteria.

Expectations for manipulation of components covered under an SCT were issued to Maintenance and Operations personnel stating that effective communication must occur between Shift Management and Maintenance prior to component manipulation. Additionally, the terms "Shift Management" and "immediately prior to" were clearly defined.

The work planning and Operations Service Group have been reorganized to facilitate improved planning and work coordination. Expectations for improved planning and coordination of work activities, especially those performed on operable equipment, have been communicated to personnel in the planning organization. This includes the expectation that appropriate information and controls related to equipment operability be documented in the work packages.

Corrective Steps that Will be Taken To Avoid Further Violations

An Operations Improvement Plant was developed December 13, 1994, to reinforce proper standards and expectations to improve overall performance. This plan will be implemented through 1995 to ensure clear understanding of roles and responsibilities of Operations personnel, involvement of upper level management when operating limits could be unnecessarily challenged, and the need to continually maintain a healthy skepticism and questioning attitude during work evolutions. This plan also includes reinforcement of management expectations regarding the conduct of pre-job briefings, verbal communication standards, and the need for heightened operator awareness and control during the conduct of work activities involving operable equipment.

Enhanced controls are being added to the VOTES test procedure. Maintenance Procedure M-511-130, "Procedure for Diagnostic Testing of Limitorque Motor Operated Valves using Liberty Technologies 'VOTES' Method" will be revised to clearly delineate a section where Operations can document restrictions or controls on the performance of VOTES testing. This revision will be completed by January 31, 1995.

Procedures governing releases of equipment for maintenance are being enhanced to provide clear guidance regarding equipment operability and control requirements. This item will be completed by March 31, 1995.

The Date When Full Compliance Was Achieved

Full compliance was achieved August 3, 1994, when MO-498 was re-opened and the ESW system was returned to an analyzed condition.

August 16, 1994

Docket No. 50-277
50-278

Mr. D. M. Smith
Senior Vice President-Nuclear
PECO Energy
Nuclear Group Headquarters
Correspondence Control Desk
P. O. Box 195
Wayne, Pennsylvania 19087-0195

Dear Mr. Smith:

SUBJECT: PEACH BOTTOM INSPECTION REPORT NOS. 50-277/94-17 and 50-278/94-17

This letter transmits the NRC Region I inspection report for the announced safety inspection conducted by Mr. A. Lohmeier of this office during the period July 25 through July 29, 1994 at the Peach Bottom Atomic Power Station in Delta, Pennsylvania. Mr. Lohmeier discussed the findings of this inspection with Mr. G. Edwards and members of the Peach Bottom engineering and licensing staff at the exit meeting on July 29, 1994.

This inspection was directed toward assessment of engineering effectiveness at the Peach Bottom Atomic Power Station in providing for the protection of public health and safety. The assessment evaluated the status of site engineering reorganization, management oversight of engineering activity, performance of the engineering organization in carrying through its assigned responsibilities, self assessment of engineering activity, effectiveness in carrying out site modifications, and the quality and effectiveness of the engineering organization in approaching issues important to protection of the public health and safety.

It was found that reorganization of the engineering department at Peach Bottom Atomic Power Station is completed. Effective management oversight is conducted through an extensive program of performance measurement and trend monitoring. Chronic system problems are identified with responsibilities directed to carry out corrective actions. A program for self assessment is carried out throughout the engineering organization. Generally acceptable performance was noted in carrying out facility modifications. Strong performance was noted in engineering ability to approach and resolve significant engineering issues related to plant operational safety.

The list of chronic problems and areas for needed performance improvement is extensive and performance objectives have been set high. The program to improve engineering personnel vision of the scope and extent of their responsibilities was found to be a pro-active one.

Improvement of computer resources to assist the engineer in carrying through his responsibilities is evident. These are positive management actions toward improving the efficiency and effectiveness of engineering personnel toward efficient and safe operation of this nuclear power generation station.

9408290002 2pp

There have been found no violation of regulations and no reply to this letter is required. Your cooperation with us is appreciated.

Sincerely,

(original signed by)

Michael C. Modes, Chief
Materials Section
Division of Reactor Safety

Enclosure: NRC Region I Inspection Report Nos. 50-277/94-17 and 50-278/94-17

cc w/encl:
J. Doering, Chairman, Nuclear Review Board
G. Rainey, Vice President, Peach Bottom Atomic Power Station
W. H. Smith, III, Vice President, Nuclear Station Support
D. B. Fetters, Director, Nuclear Engineering
C. Schaefer, External Operations - Nuclear, Delmarva Power & Light Co.
G. Edwards, Plant Manager, Peach Bottom Atomic Power Station
A. J. Wasong, Manager, Experience Assessment
G. A. Hunger, Jr., Director, Licensing
J. W. Durham, Sr., Senior Vice President and General Counsel
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Lohmeicr	Modes
08/ /94	08/ /94

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

DOCKET/REPORT NO.:	50-277/94-17 50-278/94-17
LICENSEE:	PECO Energy
FACILITY:	Peach Bottom Unit Nos. 2 and 3
DATES:	July 25 through 29, 1994
INSPECTOR:	A. Lohmeier, Senior Reactor Engineer, MS, DRS

SUBMITTED BY:

(original signed by) P. Patnaik for 8/16/94

A. Lohmeier, Senior Reactor Engineer Date
Materials Section
Division of Reactor Safety

APPROVED BY:

(original signed by) 8/16/94

Michael C. Modes, Chief Date
Materials Section
Division of Reactor Safety

Area Inspected: The inspection included the assessment of engineering activity at the Peach Bottom Atomic Power Station (PBAPS) in providing for the protection of public health and safety. The assessment evaluated the site organization and management oversight of engineering activity, performance of the engineering organization in carrying through its assigned responsibilities, licensee self assessment of its engineering and technical support activity, effectiveness in carrying out site modifications, and the quality and effectiveness of the engineering organization in approaching issues important to protection of the public health and safety.

Results of Inspection: Reorganization of the engineering department at PBAPS is completed. Effective management oversight is conducted through an extensive program of performance measurement and trend monitoring. Chronic system problems are identified with directed responsibilities to carry out corrective actions. A program for self assessment is carried out throughout the engineering organization. Generally acceptable performance was noted in carrying out modifications. Strong performance was noted in engineering ability to approach and resolve major engineering issues related to plant operational safety. Strong action is being carried out toward improvement of system manager vision of their responsibilities.

DETAILS

1.0 SCOPE OF INSPECTION (INSPECTION PROCEDURE 37550)

The scope of this inspection included the assessment of engineering and technical support activity at the Peach Bottom Atomic Power Station in providing for the protection of public health and safety. The assessment evaluated the site organization and management oversight of engineering activity, performance of the engineering organization in carrying through its assigned responsibilities, licensee self assessment of its engineering and technical support activity, effectiveness in carrying out site modifications, and the quality and effectiveness of the engineering organization in approaching issues important to protection of the public health and safety. The inspection was conducted at the Peach Bottom Atomic Power Station of PECO Energy in Delta, Pennsylvania.

2.0 SITE ENGINEERING ORGANIZATION AND MANAGEMENT OVERSIGHT

2.1 Status of Nuclear Effectiveness and Efficiency Design Study (NEEDS) Engineering Division Reorganization

The inspector found that the NEEDS reorganization of PBAPS engineering was complete. This reorganization was a major effort by the PECO Nuclear Group to improve its effectiveness in providing for the safe and efficient generation of nuclear electric power. In reviewing the planning and carrying out of this program, the inspector found that it was carried through effectively, efficiently, and according to a well-planned schedule. This performance is commensurate with the quality of management expected in a nuclear power generation facility.

The inspector found no significant changes in the reorganized engineering department format or responsibilities other than a change in the manager of the component engineering section. The replacement for this position came from the Chesterbrook engineering organization. He had a record of effective performance in his past responsibilities as a project manager at Chesterbrook.

In discussion with the Director of Engineering, the inspector noted that a significant effort is being expended in the improvement of the vision of system managers to the scope of their responsibilities. The existing vision of a system engineer of his responsibilities was not congruent with management expectations. The management expectation of the system manager vision is for him to have the responsibility and authority with which to harness the resources of the Nuclear Group toward resolving the problems within his system. The responsibilities of the system manager is now communicated to be greatly expanded. The system manager is required monitoring system trends of his system with modern computer technology. This technology provides for data retrieval and trend analysis that allows the system manager to more effectively avert the consequences of equipment failure by alerting him to changes in equipment operating characteristics. Since the system manager is an important engineering function at an operating plant, the inspector believes the licensee efforts to be a pro-active improvement.

2.2 PBAPS Mission, Objectives, and Goals

The PBAPS 1994 mission, operational objectives and goals are clearly publicized throughout PBAPS. The stated mission of PBAPS is to generate electricity safely, reliably and efficiently in compliance with federal, state, and local regulatory requirements, applicable industry technical standards, quality assurance requirements, and company policies. Toward that end, operational objectives have been set for safety, regulatory performance, financial performance, investment protection, internal and external relations, and organizational effectiveness. The inspector noted that these objectives were monitored monthly, and the performance under each operational objective noted in the performance indicator summary distributed each month.

3.0 PERFORMANCE ASSESSMENT OF ENGINEERING ACTIVITY

3.1 PBAPS Annual Performance Self Assessment Summary

The inspector reviewed the PBAPS 1994 Annual Self-Assessment Report. The report discusses the self-assessment findings for each Division at PBAPS. In each section, overall organizational strengths and weakness findings of site engineering and each engineering section are discussed together with an action plan for each finding. Findings are issues that performance did not meet management's expectations, procedural compliance,regulatory requirements, nuclear group goals, or cost efficient plant operation. The evaluation covered plant, maintenance, site support services, outage management, site engineering, and training divisions.

The self-assessment of site engineering indicated strengths in organizational performance as observed from positive trends on the "Step-Up to 95" program performance indicators. Effective disposition was noted of non-conformance reports (NCR's) for the majority of motor operated valve (MOV), erosion-corrosion issues, and equivalent change requests (ECR's), implementation of the small modification process in solving chronic equipment problems and design equivalent changes (DEC's) resulting in reduced maintenance or instrumentation and control (I&C) backlog. Development of on line flux tilt technology for reliable detection and suppression of fuel leakers were positive performance indicators.

Organizational findings indicated interface between site engineering branches is less than adequate and expectations for system managers have not been clearly communicated. Planned corrective actions include periodic interface meetings and communication of management expectations for system managers through training presentations.

Plant engineering section findings indicated fuel pool housekeeping is less than adequate, plant performance monitoring needs improvement, system manager meeting coordination is less than adequate, work processes are cumbersome and inefficient, and modification lead station representative (LSR) duties are time consuming. Corrective actions include forming task teams to evaluate fuel pool conditions and controls, initiation of performance monitoring reports, holding effective interface meetings by improving communication, evaluating processes in plant engineering for improvement, and reviewing LSR duties for improvement.

Component engineering section findings indicated coordination, ownership, and responsibilities for MOV program need improvement, insufficient resources are available for the in-service testing program and shift engineer support. LLRT procedures require improvement, and ASME code compliance is hampered by lack of needed validation of ASME Section XI in the plant information management system (PIMS). Corrective actions have not been defined and scheduled by PBAPS in their self-assessment report as they have been for other sections.

Design engineering section findings indicate that improvement is necessary in knowledge of PBAPS processes. The procurement and vendor manual processes need improvement. Access to calculations needed for operability decisions on irregular shifts have caused difficulty, and engineering processes have not been tied electronically to the work prioritization process. Corrective actions include training to improve engineer's knowledge of PBAPS processes, improvement of the procurement and vendor manual process, study of the feasibility of transferring engineering calculations from Chesterbrook to Peach Bottom, and evaluating transfer of computerized prioritization process to assist engineering processes.

The performance and reliability section findings indicate a lack of customer focus, some ineffective corrective actions have been ineffective, procedure

preparation and revision controls that are not easily interpreted by users, and administrative guideline requirements for failure trending that are not being met. Corrective actions include development of a customer focus performance improvement plan, development of program ownership expectations, solicitation of customer suggestions for improvement of highest impact procedures, and revision of the failure trending guideline to improve utilization of resources on safety components.

3.2 PBAPS Monthly Performance Indicator Summary

The inspector reviewed the PBAPS Monthly Update Report, June 1994, Performance Indicator Summary. This document provides for the ongoing assessment of PBAPS performance as determined from PBAPS performance indicators related to satisfaction of PBAPS goals in support of Nuclear Group operational objectives. The inspector found the performance of PBAPS relative to safety, regulatory performance, financial performance, investment protection, internal and external relations, and organizational effectiveness generally meeting the established goals. Review of the indicators showed favorable performance in all performance goal categories, with the exception of Safety and Regulatory Performance. The safety goals not met were those of lost work week accidents and personnel radiation exposure. The regulatory performance goal not met was due to not learning from analysis of unusual events to preclude repetitive failures. From these observations, however, no general engineering performance deficiency was found that contributed to lack of attention to the mission and goals.

The items of interest to assessment of the engineering organization include the average gross generation, unplanned automatic scrams, unavailability of emergency core cooling system components, age of open issues, causes of licensee event reports, NRC inspection results, commitments and open items, status of vendor manual reports, procedure revisions, unit capability factor, thermal performance, modification implementation performance, Nuclear Plant Reliability Data Systems Group (NPRDS) performance indicators, design change documentation, non-conformance report trend status, design equivalent change requests, and engineering change requests.

The inspector found direct or indirect performance in these areas generally consistent with established goals. The monitoring of performance in these areas was in sufficient detail for management to identify problem areas and take timely corrective action in resolution of the problems. The monthly performance indicator summary provides for continuous oversight of a wide range of engineering performance related to safe operation of the plant.

3.3 Independent Safety Engineering Group (ISEG) Performance Assessment

The inspector reviewed the 1993 Annual Summary Assessment Report for PBAPS. The ISEG is an independent organization reporting to the Nuclear Group Headquarters management at Chesterbrook. ISEG provides an independent overview of engineering safety performance at PBAPS. The ISEG staff dedicated to PBAPS oversight is stationed at PBAPS. They have written 20 inspection reports in 1993 and approximately 10 inspection reports in 1994 to date. The reports address the PBAPS safety performance through a collection of strengths and weaknesses identified by other monitoring groups and assesses the performance in each functional area. Station performance data is assessed to determine whether station is operating within an appropriate nuclear safety culture.

PBAPS engineering strengths noted by ISEG include effective technical support of safe operations in 1993, quality engineering participation in technical evaluation and response to safety issues such as the cracks found in core shroud welds, communications with other divisions, support of operating procedures, and improved configuration control.

PBAPS engineering weaknesses identified by ISEG include inadequate trending of system performance, weak procedural usage, inadequate design information associated with plant changes, weak engineering management processes for control, and marginal execution of work tasks. Attention is required to improve drawing accuracy. Training of station support engineering personnel was found to be less than adequate. Engineering activities were insufficiently effective in identifying and resolving plant equipment problems. Procedural compliance was shown to be weak in various areas. Incomplete and inaccurate engineering evaluation of changes to the plant and design basis was described as a pervasive weakness. Weaknesses exist in management of engineering work and station support engineering.

The review of engineering performance by ISEG contributes to the overall assessment by providing an independent observation from an organization outside the control of PBAPS. The inspector notes that the strengths and weaknesses found by ISEG touch upon those identified in PBAPS self-assessments and draw similar, although not exactly, the same detailed conclusions. Generally, the observations of ISEG confirm the important observations of the self-assessment summaries.

3.4 Chronic System Problem Resolution

The inspector noted that PBAPS has replaced the "Baker's Dozen" concept of identifying the PBAPS 13 most chronic problems with a list of Peach Bottom Equipment/System Problems. The new chronic problem list provides for each problem a description of the problem, the action required for solution of the problem, the next action to be performed, and the status relative to completion. The present list is not limited to 13 items.

Included in the list of chronic problems at PBAPS are problems requiring engineering action and implementation plans, problems awaiting implementation of solution, and resolved problems. These are identified as follows:

A. Problems Requiring Engineering Action and Implementation Plans

Cooling tower structural, leakage, pump and motor operation
Cathodic Protection
HPCI operation reliability
RMC (RPIS and PIPS) position indication problems
CAD injection valve failures to pass required [illegible]
Feedwater control deficiencies, high vibration, lubrication leakage
HPSW Pumps and Heat Exchanger operation flexibility, operation
Fuel pool cooling hot spots
SRM and IRM reliability
Traversing incore probe detectors failure rates, system reliability
In-Service testing failures without pump degradation
Recombiner hydrogen analyzers
Feedwater heater level swings
Auxiliary Boiler reliability and availability
Motor Operated Valve performance
Condensate demineralizer air admission solenoid failure
Traveling screen reliability
Hypochlorite system pipe leaks, injection rate balance
Condenser cleanliness

B. Problems Awaiting Solution Implementation

Reactor water cleanup pump operation
Containment Atmospheric Dilution equipment Hydrogen and Oxygen analysis and injection system qualification and reliability
Electro-Hydraulic Control maintenance, leakage, malfunctions

Plant heating system equipment leakage and maloperation
HPSW Radiation Monitors design inadequacies
Reactor vessel head drain system design problems
TA relays on valves and pumps failure history
Instrument nitrogen system compressor failures
Recirculation system equipment maloperation

C. Resolved Problems

480 V LC Cross Tie Breakers
Water Treatment Plant

The foregoing list of chronic problem areas is an indication of the large number of chronic problems requiring engineering attention at PBAPS. The problems are openly identified with solutions and expected actions to be forthcoming in the resolution of these problems. The large number of problems that exist gives credence to the efforts of the engineering department to improve performance. The resolution of these problems will be followed by the inspector during future engineering inspections at PBAPS.

3.5 PBAPS "Step Up to 95 Program"

The inspector reviewed the PBPS "Step Up to 95 Program" designed to effect a measurable change in site personnel performance by January 1995. Action goals have been established by which the program can be monitored. Management personnel have been identified with responsibility for achievement of each goal. Actions include management oversight meetings to plan, monitor, review, and train engineering personnel. Improvements targeted will be in improvement of non-conformance report and equivalent change request response, vendor manual review, procurement processes, and improvement of inadequate site resources to assist engineering performance.

3.6 Summary of PBAPS Performance Monitoring Programs

PBAPS has expended considerable effort in identification of areas where performance improvement of engineering activity is appropriate. Assessment of engineering performance has been made through the PBAPS Annual Performance Assessment Summary, PBAPS Monthly Performance Indicator Summaries, ISEG Performance Assessments, and PBAPS Peach Bottom Equipment/System Problem Identification. From these assessments of performance, it is apparent that PBAPS is faced with resolution of many problems in effective operation of the plant. The chronic problem list is a significantly large one, and it underscores the large number of challenges to the engineering staff.

The PBAPS management team, in recognition of the large number of challenges has directed its resources to improvement in the ability and vision of its engineering staff to obtain improvement in engineering personnel responsibility and vision of the task before them. Management also has indicated it will review the resources given the engineering personnel to assist them in meeting the large number of challenges efficiently and effectively. The resources are now providing improved computer technology for the use of engineers in monitoring and trending system performance.

PBAPS has shown the inspector many positive changes in performance since the NEEDS reorganization. The planning and improvement initiatives have been creative and appear to be directed at solution of significant engineering issues. The results of these initiatives can be viewed only after observing performance changes over a future period of time in resolution of the many problem area findings.

4.0 REVIEW OF ENGINEERING ISSUE RESOLUTION AND MODIFICATION IMPLEMENTATION

4.1 Review of Engineering Issue Resolution

The inspector reviewed several significant engineering issues to assess the performance of the engineering personnel in identifying the issue, determining the corrective action required to resolve the issue, and implementing the corrective action in an effective manner. Of importance to the resolution of any issue is to provide for the proper personnel and resources.

4.1.1 Reactor Core Shroud Cracking

The inspector reviewed PBAPS engineering participation in the core shroud cracking problem. A discussion with the responsible engineer covered the generic issue of core shroud cracking from the Brunswick issue through the finding of core shroud cracking at PBAPS to the future planning of actions.

After learning about the Brunswick core shroud cracking problem, PBAPS worked with General Electric Company and determined the need to develop an inspection plan for the PBAPS Unit 3 reactor core shroud. PBAPS engineers visited Brunswick and determined the magnitude of the inspection problem and resources required in its resolution. A visual inspection was performed of the core shroud barrel. With assistance of General Electric, Chesterbrook Engineering, Stone and Webster, and Structural Integrity Associates, PBAPS engineering made a safety assessment of the visual inspection findings and management decided to restart and operate until the next scheduled outage. NRC was actively involved in oversight of the safety of the decision to restart. In projecting action at the next scheduled outage, it was decided that General Electric will perform ultrasonic testing of the core shroud barrel.

In recognition of the seriousness of the problem, PBAPS is an active participant in the BWR Vessel and Internals Project (VIP). PBAPS holds membership in all 5 task groups, including integration, inspection, assessment, mitigation, and repair of reactor internals. Members are from major BWR facilities throughout the United States and EPRI.

PBAPS is considering the necessity of inspecting Unit 2, but they have not made the decision to proceed in the inspection. Preparations are being planned and designs of attachments are being reviewed if further inspection deems it appropriate. Management oversight responsibilities have been identified at PBAPS including the PBAPS Vice President, Plant Manager, and Engineering Director.

PBAPS engineering performance in approaching the problem of reactor core shroud cracking is consistent with good engineering practice and demonstrates the attention given by management to problems having safety significance.

4.1.2 Fatigue Monitoring Program (URI 90-14-02)

The inspector found that resolution of unresolved item (URI) 90-14-02 was on schedule. Progress has been made in carrying forth the commitments related to reactor pressure vessel fatigue cycle monitoring. An Action Request (A/R) has been written which describes the scope of the action plan. The scope includes revision of the routing test procedure, cycle counting methodology, retrieval of data from the archives, preliminary review to verify adequacy of methodology, review and evaluate data, preparation of a table of expended cycles to compare with FSAR table of design cycles, and evaluation of the total expended fatigue life. Completion of this A/R is anticipated by December 31, 1994.

The inspector reviewed the procedure ST-J-080-940-2(3) that provides for regular recording of data. A table of cyclic data to be recorded was reviewed by the inspector. The methodology for transient cycle evaluation was developed in March, 1994. Information has been retrieved , reviewed, and determined to be useful in the historical investigation of transient operation. These data include temperature recording charts, control room logs, computer output, working files, power plots, monthly operating reports, licensee event reports, scram reports, design fatigue evaluation notebook entries, previous counting procedures, and information from other power plants. Further data is expected from upset reports. PBAPS found that the methodology for tallying of cyclic events may be changed, and provision will be made for describing the reasons for changing the tallying methodology.

The performance of PBAPS engineering toward development of a comprehensive fatigue monitoring system is found to be good. It is anticipated that the completion date of December 31, 1994 will be met. At that time, PBAPS will have a comprehensive fatigue monitoring system in service.

4.2 Plant Modification Implementation

The inspector reviewed the implementation of several modifications. Of interest to the inspector was the knowledge of the system manager of the reason for the modification, and the clarity of the 10 CFR 50.59 safety review (SR) and the design information document (DID).

4.2.1 Unit 3 HPCI Steam Supply Drain Pot Drain Line Vibration (NCR PB 94-000960)

The inspector reviewed the Unit 3 high pressure coolant injection steam supply drain pot drain line vibration problem. The one inch pipe line was found to be vibrating excessively. It vibrates from the drain pot to the north wall. Included in the vibrating line is the steam supply drain pot level switch line.

From an investigation of the vibration problem, PBAPS found that a "U" clamp holding the pipe line is loose and requires replacement. The licensee further concluded that the addition of additional supports could bind the pipe and not allow free expansion under changing thermal loads.

There is no attached operating equipment to the piping system. Therefore, no alternating mechanical exciting forces are the cause of the vibration. The inspector believes the caution of the licensee in not over-restraining the pipe is appropriate. The root cause of the vibration must be more clearly understood as well as the analysis of the cyclic stresses due to thermal expansion restraint. The licensee is presently giving consideration to both finding the root cause of vibration and solution of the thermal restraint problem.

In discussion with the licensee engineers responsible for solution of this problem, the inspector notes that the technical understanding of the problem is apparent and solution requires the expenditure of time in performing the analyses necessary to determine the root cause of the vibration and the feasibility of solutions to the problem.

4.2.2 RHR System Manual Block Valve in Equalizer Line (Modification 5383)

The inspector reviewed the modification to install a manual block valve in the equalizer line of the residual heat removal loop check valve AO-46A(B), which is a containment isolation valve. The modification allows performance of a leak test in accordance with PBAPS Technical Specification Table 3.7.4 and will help determine whether the check valve or isolator valve is leaking

during the leak rate test. Similar valves have also been added in the core spray equalizer lines. The block valve is locked open during operation to avoid inadvertent closing.

The inspector found the design input document to be comprehensive. The 10 CFR 50.59 safety evaluation was found to be comprehensive. It met the regulatory requirements for installation of the modification. The system manager responsible for this modification was found to be knowledgeable and able to communicate the technical details of the problem and its solution to the inspector.

4.2.3 Permanently Opening Emergency Service Water Inlet Valves (Modification P00424)

The inspector discussed the modification to permanently open the emergency service (ESW) inlet valve to the emergency core cooling system (ECCS) and reactor core isolation cooling (RCIC) system room coolers. The existing system, requiring an air operated ESW valve, has poor reliability, and can cause the inlet valve to remain closed. The modification will permanently block the valve open by isolating instrument air from the inlet valve. Permanently opening the ESW valve will result in increased flow to the room coolers, but has no impact on the safety-related flow requirements.

The inspector found the design input document to be comprehensive. A preliminary copy of the 10 CFR 50.59 was found to be comprehensive and it met the regulatory requirements for installation of a modification. The system manager responsible for this modification was found to be knowledgeable and able to communicate the technical details of the problem and its solution to the inspector.

4.3 Temporary Plant Alterations (TPAs)

The inspector reviewed a list of PBAPS TPAs. It was noted that in June 1994 there are a total of 22 TPAs for Unit 2 and 17 TPAs for Unit 3. The total number of TPAs has decreased from a high of 48 in February of 1993 to a low of 32 in December of 1993. Since that time the number has risen to 39.

Of interest to the inspector were the reasons for the TPAs, the TPA removal methods, and the ages of the TPAs at removal. These statistics were shown in pie charts in the TPA Monthly Report for June, 1994.

The reason distribution for TPAs are that 41% are awaiting permanent modifications, 36% are for equipment problems, and 21% are to allow trouble-shooting of problems. The distribution of reasons for removal of TPAs are 44% to install modifications, 41 % from action requests, and 13% on completion of troubleshooting. The age distribution of TPAs is that 33% are removed in less than 3 months, 28% remain for over 1 year, 10% remain for over 6 months, 13% remain for over 3 months, and 15% remain for over 2 years.

The inspector noted that PBAPS has great sensitivity to the ageing of TPAs. When TPA requests are presented for approval at Plant Operations Review Committee (PORC) meetings, it is required that a date be established for removal of the Temporary Modification. This sensitivity is confirmed by the issuance of a monthly report on TPA activity status.

5.0 MANAGEMENT TRAINING

PBAPS has many programs for training engineering personnel. At the present time, training of system managers is of prime importance to plant operation. The inspector inquired about the amount of training given management personnel. It was indicated to the inspector that first level management must attend a 3 week offsite "Supervisory Development Institute" after given

mana- .ment responsibility. Senior Managers and Directors attend "Leadership Exchange" meetings. Because of the importance of training to effective engineering management, the inspector will review the training of engineering management personnel at continuing engineering inspections over the remaining SALP cycle.

6.0 SUMMARY AND CONCLUSIONS

- The inspector found that the NEEDS reorganization of PBAPS engineering was carried through effectively, efficiently, and according to the planned schedule. This performance is commensurate with management expected in a nuclear power generation facility.
- Significant licensee effort is being expended in the improvement of the vision of system managers toward having the responsibility and authority with which to harness the resources of the Nuclear Group toward resolving the problems within his system. Computer technology is provided to assist system manager to more effectively avert the consequences of equipment failure.
- The PBAPS 1994 mission, operational objectives and goals are clearly publicized to personnel throughout PBAPS.
- PBAPS has expended considerable effort in identification of areas where performance improvement of engineering activity is appropriate. Several means of engineering performance measurement have shown many positive changes in performance since the NEEDS reorganization.
- The performance of engineering personnel in identifying the issue, determining the corrective action required to resolve the issue, and implementing the corrective action in an effective manner was found to be generally good on significant safety related issues.
- The large number of chronic problem areas is an indication of the number of problems requiring engineering attention at PBAPS. The large number of problems that exist lends credence to the efforts of the engineering department to improve performance.
- The knowledge of system managers of the reasons for modification, the clarity of the 10 CFR 50.59 safety reviews, and the design information document was found to be good.
- PBAPS has demonstrated great sensitivity to the ageing of temporary plant alterations by the issuance of a monthly report on TPA activity status.

7.0 MANAGEMENT MEETINGS

The inspector met with licensee representatives at the entrance meeting on July 25, 1994, and at the exit meetings on July 29, 1994, at the Peach Bottom Atomic Power Station in Delta, Pennsylvania. The names of licensee personnel contacted are shown on Attachment A.

The findings of the inspection were discussed with licensee management at the July 29 exit meeting. The licensee did not disagree with the findings of the inspector.

Attachment A: Entrance and Exit Meeting Attendance List

APPENDIX A

Personnel Contacted During the Inspection

PECO ENERGY COMPANY

*	J. Armstrong	Sr. Manager	Plant Engineering
	R. Barnett	Engineer	Operations Support
	O. Brown	Manager	Procurement
*	J. Carey	Site Rep	Public Service Electric and Gas Co.
*	F. Cook	Sr. Manager	Design Engineering
	D. Dycus	Engineer	Nuclear Quality Assurance
*	G. Edwards	Manager	PBAPS
	A. Fulvio	Manager	Nuclear quality Assurance
*	M. Hammond	Manager	Performance and Reliability
*	J. Jordan	Manager	Engineering Training
*	D. Keene	Manager	Instruments and Control Engineering
	K. Kinard	Manager	Documentation Services
*	O. Limpias	Manager	Civil/Structural Design Engineering
*	T. Moore	Manager	Component Engineering
*	T. Niessen	Director	Site Engineering
*	F. Polaski	Manager	Independent Safety Engineering
*	R. Smith	Engineer	Experience Assessment
	L. Sollenberger	Engineer	Nuclear Quality Assurance
	J. Staniciewicz	Director	Training
	C. Swensen	Manager	Maintenance Planning
	D. Warfel	Manager	Operations Support
	A. Wasong	Manager	Experience Assessment
	C. Wiedersum	Manager	Mechanical Design Engineering

UNITED STATES NUCLEAR ENERGY COMMISSION

R. Lorson	Inspector	NRC Region I

* Indicates attendance at the exit meeting July 29, 1994.

XCS

November 4, 1994

Mr. D. M. Smith
Senior Vice President-Nuclear
PECO Energy Company
Correspondence Control Desk
P. O. Box 195
Wayne, PA 19087-0195

SUBJECT: COMBINED INSPECTION 50-277/94-21 AND 50-278/94-21

Dear Mr. Smith:

This letter transmits the findings of the resident safety inspection conducted by Messrs. W. L. Schmidt, F. P. Bonnett, and R. K. Lorson, from August 28, 1994, through October 8, 1994, at the Peach Bottom Atomic Power Station, Delta, Pennsylvania. The inspectors based these findings on observation of activities, interviews, and document reviews, and discussed them with Mr. G. Edwards of your staff.

Your staff commenced the Unit 2 refueling outage during this period. Unit 2 activities, including plant shutdown and outage activities, were conducted well. In particular, refueling activities and core shroud inspections were properly controlled and maintenance technicians performed their outage activities well. Engineering provided good support for the repair of a Unit 2 residual heat removal system injection isolation valve and for the implementation of several high quality modification packages.

Unit 3 was operated safely over the period. Operators responded well to the failure of a Unit 3 secondary containment isolation valve and to a steam valve packing leak which caused an increase in drywell pressure. An unresolved item was opened regarding the inappropriate use of a temporary change to an emergency service water system operating procedure.

Despite the generally good performance during the Unit 2 outage, there were several issues involving personnel performance weaknesses. These issues are of concern because of their similarity to events discussed in several recent inspection reports. Further, the events were preventable and they caused unexpected and unnecessary challenges to the operators and plant staff. Some of the events resulted from poor coordination, communications, and self-checking by personnel and others were due to inadequate preparation and review of the impact of electrical equipment isolations on plant equipment. Although each event was not safety significant on an individual basis, it appears that your staff's efforts to address past personnel performance concerns have not been fully effective.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room. The responses directed by this letter and the enclosed Notice are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. No. 96.511.

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We appreciate your cooperation.

Sincerely,

Original Signed By:
Clifford J. Anderson

Clifford J. Anderson, Section Chief
Projects Section 2B
Division of Reactor Projects

Docket/License No. 50-277/DPR-44; 50-278/DPR-56

Enclosure:
1. NRC Region I Combined Inspection Report 50-277/94-21 and 50-278/94-21

cc w/encl:
J. Doering, Chairman, Nuclear Review Board
G. Rainey, Vice President, Peach Bottom Atomic Power Station
W. H. Smith, III, Vice President, Nuclear Station Support
D. B. Fetters, Director, Nuclear Engineering
A. F. Kirby, III, External Operations - Nuclear, Delmarva Power & Light Co.
G. Edwards, Plant Manager, Peach Bottom Atomic Power Station
A. J. Wasong, Manager, Experience Assessment
G. A. Hunger, Jr., Director, Licensing
J. W. Durham, Sr., Senior Vice President and General Counsel
J. A. Isabella, Director, Generation Projects Department,
Atlantic Electric
B. W. Gorman, Manager, External Affairs
R. McLean, Power Plant Siting, Nuclear Evaluations
D. Poulsen, Secretary of Harford County Council
R. Ochs, Maryland Safe Energy Coalition
J. H. Walter, Chief Engineer, Public Service Commission of Maryland
Public Document Room (PDR)
Local Public Document Room (LPDR)
Nuclear Safety Information Center (NSIC)
D. Screnci, PAO (2)
NRC Resident Inspector
Commonwealth of Pennsylvania
TMI - Alert (TMIA)

bcc w/encl:
Region I Docket Room (with concurrences)
K. Gallagher, DRP

bcc w/encl: (Via E-Mail)
W. Dean, OEDO
J. Shea, NRR
J. Stolz, PDI-2, NRR
M. Shannon, ILPB

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U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/94-21 50-278/94-21	License Nos. DPR-44 DPR-56
Licensee:	PECO Energy Company P. O. Box 195 Wayne, PA 19087-0195	
Facility Name:	Peach Bottom Atomic Power Station Units 2 and 3	
Dates:	August 28 - October 8, 1994	
Inspectors:	W. L. Schmidt, Senior Resident Inspector F. P. Bonnett, Resident Inspector R. K. Lorson, Resident Inspector	
Approved By:	Clifford J. Anderson C. J. Anderson, Chief Reactor Projects Section 2B Division of Reactor Projects	11/4/94 Date

EXECUTIVE SUMMARY
Peach Bottom Atomic Power Station
Inspection Report 94-21

Plant Operations

The inspectors found that the operators conducted routine activities safely during the period (Section 2.0). At Unit 3, operators responded well to a secondary containment isolation valve failure (Section 4.3) and to increasing drywell pressure caused by a packing leak on the inboard high pressure coolant injection (HPCI) steam supply isolation valve (Section 2.2). Also, the operators promptly recognized and corrected a condensate storage tank low level condition (Section 2.1.2).

The Unit 2 refueling outage activities were conducted well and good coordination was observed between the station groups (Section 2.1). The fuel handling activities were well controlled (Section 2.1.1).

Several areas of weak operator performance were noted involving: less than adequate review of equipment blocking permits (discussed below); a slow response to an air leak into the reactor cavity (Section 2.1.2); and multiple logkeeping deficiencies (Section 2.5).

The morning leadership and Nuclear Review Board meetings continued to provide good oversight of plant operations (Section 2.4).

Maintenance and Surveillance

Maintenance activities performed during the Unit 2 refueling outage including the emergency electrical bus outages (Section 4.1), and repair of a residual heat removal system injection isolation valve (Section 4.2) were well controlled (Section 2.1). Isolation of a steam packing leak inside the Unit 3 drywell (Section 4.4), and support for the 3D high pressure service pump motor bearing failure investigation (Section 4.5) were also conducted well.

Surveillance and modification testing including containment leakrate (Section 3.1), emergency electrical bus undervoltage (Section 3.2) and station blackout testing (Section 3.4) were performed well.

Despite the generally good control of outage activities, several events occurred that demonstrated poor coordination, communications, and self-checking (Section 2.1.2). These included: a mis-aligned refueling bridge mast; two occurrences where reactor level indication was unexpectedly lost during the reactor vessel head removal; and an untimely notification of the reactor services supervisor regarding a broken fuel rod.

Clearance and tagging errors resulted in several unexpected plant events including: a loss of shutdown cooling; inability to restore shutdown cooling; loss of reactor cavity clarity; and operation of three instrument air compressors without supplying cooling water (Section 2.1.4).

Engineering and Technical Support

Engineering provided good support for plant operations and maintenance activities. The modification packages for the improved refueling level instrumentation (Section 5.1) and improved 4kV bus off-tie transfer circuitry were of high quality. The investigation into suspected Unit 2 fuel leaks (Section 2.1.1) and the analysis performed to support the repair of a Unit 2 residual heat removal inboard isolation valve (Section 4.2) were good.

The chronic equipment list was utilized effectively to develop long term actions for resolution of equipment reliability problems (Section 5.2). Also, the inspectors determined that none of the items on the chronic equipment list presented a safety concern.

A temporary change (TC) issued to an emergency service water system operating procedure appeared to be an intent change and therefore beyond the scope of a TC (Section 5.3). This issue remains unresolved **(Unresolved 94-21-01)**.

Unresolved Item 93-25-02 involving the mis-operation of the time armature resistance relays in the high pressure coolant injection system motor controllers was closed.

Plant Support

Material and housekeeping conditions in the Unit 2 torus were excellent and PECO responded appropriately to inspector concerns involving a cluttered Unit 2 drywell condition (Section 2.1.1).

Observed radiological controls (Section 6.1) and physical security activities were found to be acceptable.

TABLE OF CONTENTS

DETAILS

1.0 PLANT ACTIVITIES REVIEW (71707)*

1.1 PECO Energy Company Activities

The PECO Energy Company (PECO) conducted normal operating and shutdown activities at Peach Bottom Atomic Power Station (PBAPS) Unit 2 and Unit 3 safely over the period.

Unit 2 began the inspection period operating at about 74% power in an end-of-cycle-coastdown mode. The control room staff removed the 2B reactor feedwater pump (RFP) from service on September 5, when two RFPs could maintain stable operation. A load drop to 48% power occurred on September 10 to perform flux tilt testing in an attempt to identify any additional fuel leakage before the Unit 2 outage. No additional fuel leakage was identified and operators returned the plant to maximum power on September 12, 1994.

The tenth refueling outage for Unit 2 began on September 16, 1994. Major modifications implemented during the outage included the installation of a digital recirculation control system; reactor water clean-up system improvements; and the power rerate modification. Major maintenance activities included replacement of the 2A recirculation pump motor and pump internals, and inspection of the core shroud. At the end of the period the outage was about 70% complete and was generally on schedule.

Unit 3 operated at essentially 100% power for the entire period. The control room staff began a reactor shutdown on August 31, 1994, due to entering a technical specification (TS) shutdown limiting condition of operation (LCO) for a failed secondary containment isolation valve (Section 4.3). Power was restored to 100% for the remainder of the period following resolution of the failed containment valve. Operators and plant management responded well in identifying and correcting the cause of an increase in drywell pressure and unidentified leakage. The leakage was identified and isolated by backseating the high pressure coolant injection (HPCI) inboard steam supply isolation valve (Section 4.4).

1.2 NRC Activities

The resident and regional based inspectors conducted routine and reactive inspection activities concerning operations (Section 2.0), surveillance (Section 3.0), maintenance (Section 4.0), engineering and technical support (Section 5.0), and plant support (Section 6.0). The inspectors conducted these activities during normal and off-normal (backshift) PECO work hours. There was a total of 17 and 18 hours of backshift and deep-backshift inspection hours, respectively.

* The inspection procedure from NRC Manual Chapter 2515 that the inspectors used as guidance is parenthetically listed for each report section.

Based on a review of an August 3, 1994, overflow of the PBAPS emergency cooling tower (ECT) the inspectors identified a condition where the emergency service water system (ESW) was operated in an unanalyzed condition. The inspectors documented this review in Special Inspection Report 94-24.

The following specialist inspections also occurred during the report period:

Date	Subject	Report No.	Inspector
8/29-31/94	Initial Licensing Examination	94-22	Sisco
9/7-14/94	Special Safety Inspection	94-24	Lorson
9/19-24/94	Outage Radiological Controls	94-23	Eckert
9/26-10/7/94	Non-Destructive Examination	94-404	Gray

2.0 PLANT OPERATIONS REVIEW (71707, 92901, 93702, 92700)

The inspectors independently found that operators conducted routine Unit 2 activities well including safely reducing reactor power to perform flux tilt testing and executing a reactor shutdown for the tenth refueling outage. While the testing did not specifically identify any additional fuel bundle leakage, it did identify several potentially leaking bundles which were added to the in-core sipping schedule.

The Unit 3 control room operators conducted routine activities well. The control room staff safely began a reactor shutdown after entering the TS shutdown LCO for an inoperable secondary containment, due to the failure of an isolation valve to close (Section 4.3). Also, operators promptly responded to an increasing drywell pressure caused by a packing leak on the inboard HPCI steam supply isolation valve (Section 2.2).

The operations crews made correct determinations of safety system operability and reportability of identified conditions. The crews adequately tracked and controlled entry into and exit from TS LCOs. The inspectors routinely verified the operability of safety systems required to support given plant conditions at both units. Housekeeping at both units remained good.

2.1 Refueling Outage - Unit 2

The inspectors attended numerous outage planning, status, and management meetings and assessed them to be effective in coordinating and communicating outage efforts. The inspectors found ongoing modification and maintenance activities well coordinated and controlled, and good radiation worker practices in use. The inspectors concluded that PECO personnel conducted activities on the refueling floor, including reactor disassembly, core sipping, fuel bundle inspection, and inspection of the reactor shroud in a well supervised and controlled manner.

Overall, PECO conducted the outage well. PECO staff and management were well informed, and they promptly raised and addressed emerging problems. Coordination between working groups was generally good. As discussed below, the inspectors conducted detailed plant tours observing good procedure usage

and only minor housekeeping problems (Section 2.1.1); however, several events occurred that caused unexpected and unnecessary challenges to the operators and plant staff. Several of the events related to a lack of coordination, communication, and self-checking by PECO personnel (Section 2.1.2). Further, several events were caused by inadequate preparation and review of the plant impact of blocking clearances (Section 2.1.3). The inspectors concluded that these events were preventable and were the result of personnel performance weaknesses.

2.1.1 Inspection Activities

- **Drywell Tours**

The inspectors toured the drywell and noted personnel access and egress walkways were blocked with mirror insulation, loose tools, and scaffolding components. The inspectors were concerned that this clutter could cause personnel to climb on components, rather than use the walkways, and this could lead to personnel injury or equipment damage. The Unit Outage Manager indicated that he would address the concerns. The inspectors made a followup drywell tour and noted that the general housekeeping conditions had improved.

- **Torus Tour**

The inspectors toured the torus and assessed that the material condition and housekeeping was excellent. During the tour, the inspectors observed surveillance testing on the torus to drywell vacuum breakers. The inspectors noted that the test was well controlled and the breakers operated smoothly.

- **Refueling Bridge Tours**

PECO fuel handling personnel performed operations in a professional and well coordinated manner. Observations of core alterations from the refueling platform indicated that the Fuel Handling Director, the Refueling Platform Operator, and the Reactor Operator functioned well. Communications between the operators and the use of fuel location aids were excellent. Further, the use of a closed-circuit television camera mounted at the end of the grapple mast was a strength. Core alterations and core verification were completed without mishap during the inspection period.

- **Fuel Sipping**

PECO performed in-core fuel sipping and positively confirmed three of the four known leaking fuel bundles. The four bundles had been identified during the previous fuel cycle during flux tilt testing. The leaking type LYG fuel bundles, which had been originally loaded during the eighth refueling outage, were located in control cells. PECO removed the leaking bundles and as a precautionary measure, all other LYG fuel bundles from the core. PECO inspected the fuel and found no debris induced defects. They determined that manufacturing defects caused the leakage. The inspectors discussed the fuel issue with the reactor engineers and determined that PECO took good actions to address and eliminate the possibility of future fuel leaks.

2.1.2 Events

Several events occurred during the outage that demonstrated a lack of coordination, communication, and self-checking by PECO personnel. The inspectors found that the safety significance of each event was low; however, the events did present unexpected and unnecessary challenges to control room operators and plant staff.

- **Unit 3 Condensate Storage Tank Level Drop**

The inspectors determined that a poorly written procedure allowed an unexpected lowering of the Unit 3 condensate storage tank (CST) level during the filling of the Unit 2 reactor refueling cavity. PECO took appropriate initial corrective actions to this condition by: securing flood-up; reviewing and issuing a temporary change to the procedure; and initiating a performance enhancement program (PEP) review.

The inspectors reviewed procedure AO 27.6-2, "Filling the Unit 2 Reactor Well, Dryer, and Separator Pit From the Condensate System, Condensate Transfer, Refueling Water Storage Tank, or Core Spray System," and noted that the procedure connected both CSTs (Unit 2's as well as Unit 3's) and the refueling water storage tank together, thus causing the Unit 3 CST level to drop (unexpectedly) during the filling of the Unit 2 reactor well. The inspector discussed this issue with the system manager who agreed with the finding and indicated that the procedure would be revised to correct the deficiency.

The safety significance of this event was low since the CST is not relied upon as a safety-related water source. The updated final safety analysis report (UFSAR) and the system's design basis document indicated that the torus was relied upon to ensure an adequate inventory for the emergency core cooling systems. The reduction in CST level would not have prevented the ECCS systems from performing their design safety functions. Also, the inspector noted that the operators promptly recognized and corrected the low Unit 3 CST level.

- **Air Bubbles Leaking Into Reactor Cavity**

During a refueling floor tour, the inspectors observed significant air bubbling from the flooded reactor cavity, without aggressive PECO radiation protection and supervisory involvement. For about 25 minutes on September 20, 1994, air bubbles were observed on the water surface during a performance of local leak rate test (LLRT) of the B feedwater header check valve. The radiation protection personnel and reactor services supervisor assumed that the air was from a LLRT and did not aggressively confirm their assumption that no adverse radiological condition existed. The inspector determined that the air was leaking past the shut feedwater header stop valve (MO-29B) located in the drywell.

The safety significance of this observation was low; however, the slow response to an abnormal condition and reliance on assumptions were of concern to the inspectors. The control room staff was monitoring the air bubbling on a close-circuit television monitor and also did not react in a timely manner to determine the source of the air or act to secure it. The inspectors

Based on a review of an August 3, 1994, overflow of the PBAPS emergency cooling tower (ECT) the inspectors identified a condition where the emergency service water system (ESW) was operated in an unanalyzed condition. The inspectors documented this review in Special Inspection Report 94-24.

The following specialist inspections also occurred during the report period:

Date	Subject	Report No.	Inspector
8/29-31/94	Initial Licensing Examination	94-22	Sisco
9/7-14/94	Special Safety Inspection	94-24	Lorson
9/19-24/94	Outage Radiological Controls	94-23	Eckert
9/26-10/7/94	Non-Destructive Examination	94-404	Gray

2.0 PLANT OPERATIONS REVIEW (71707, 92901, 93702, 92700)

The inspectors independently found that operators conducted routine Unit 2 activities well including safely reducing reactor power to perform flux tilt testing and executing a reactor shutdown for the tenth refueling outage. While the testing did not specifically identify any additional fuel bundle leakage, it did identify several potentially leaking bundles which were added to the in-core sipping schedule.

The Unit 3 control room operators conducted routine activities well. The control room staff safely began a reactor shutdown after entering the TS shutdown LCO for an inoperable secondary containment, due to the failure of an isolation valve to close (Section 4.3). Also, operators promptly responded to an increasing drywell pressure caused by a packing leak on the inboard HPCI steam supply isolation valve (Section 2.2).

The operations crews made correct determinations of safety system operability and reportability of identified conditions. The crews adequately tracked and controlled entry into and exit from TS LCOs. The inspectors routinely verified the operability of safety systems required to support given plant conditions at both units. Housekeeping at both units remained good.

2.1 Refueling Outage - Unit 2

The inspectors attended numerous outage planning, status, and management meetings and assessed them to be effective in coordinating and communicating outage efforts. The inspectors found ongoing modification and maintenance activities well coordinated and controlled, and good radiation worker practices in use. The inspectors concluded that PECO personnel conducted activities on the refueling floor, including reactor disassembly, core sipping, fuel bundle inspection, and inspection of the reactor shroud in a well supervised and controlled manner.

Overall, PECO conducted the outage well. PECO staff and management were well informed, and they promptly raised and addressed emerging problems. Coordination between working groups was generally good. As discussed below, the inspectors conducted detailed plant tours observing good procedure usage

and only minor housekeeping problems (Section 2.1.1); however, several events occurred that caused unexpected and unnecessary challenges to the operators and plant staff. Several of the events related to a lack of coordination, communication, and self-checking by PECO personnel (Section 2.1.2). Further, several events were caused by inadequate preparation and review of the plant impact of blocking clearances (Section 2.1.3). The inspectors concluded that these events were preventable and were the result of personnel performance weaknesses.

2.1.1 Inspection Activities

- **Drywell Tours**

The inspectors toured the drywell and noted personnel access and egress walkways were blocked with mirror insulation, loose tools, and scaffolding components. The inspectors were concerned that this clutter could cause personnel to climb on components, rather than use the walkways, and this could lead to personnel injury or equipment damage. The Unit Outage Manager indicated that he would address the concerns. The inspectors made a followup drywell tour and noted that the general housekeeping conditions had improved.

- **Torus Tour**

The inspectors toured the torus and assessed that the material condition and housekeeping was excellent. During the tour, the inspectors observed surveillance testing on the torus to drywell vacuum breakers. The inspectors noted that the test was well controlled and the breakers operated smoothly.

- **Refueling Bridge Tours**

PECO fuel handling personnel performed operations in a professional and well coordinated manner. Observations of core alterations from the refueling platform indicated that the Fuel Handling Director, the Refueling Platform Operator, and the Reactor Operator functioned well. Communications between the operators and the use of fuel location aids were excellent. Further, the use of a closed-circuit television camera mounted at the end of the grapple mast was a strength. Core alterations and core verification were completed without mishap during the inspection period.

- **Fuel Sipping**

PECO performed in-core fuel sipping and positively confirmed three of the four known leaking fuel bundles. The four bundles had been identified during the previous fuel cycle during flux tilt testing. The leaking type LYG fuel bundles, which had been originally loaded during the eighth refueling outage, were located in control cells. PECO removed the leaking bundles and as a precautionary measure, all other LYG fuel bundles from the core. PECO inspected the fuel and found no debris induced defects. They determined that manufacturing defects caused the leakage. The inspectors discussed the fuel issue with the reactor engineers and determined that PECO took good actions to address and eliminate the possibility of future fuel leaks.

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The safety significance of this event was low since the CST is not relied upon as a safety-related water source. The updated final safety analysis report (UFSAR) and the system's design basis document indicated that the torus was relied upon to ensure an adequate inventory for the emergency core cooling systems. The reduction in CST level would not have prevented the ECCS systems from performing their design safety functions. Also, the inspector noted that the operators promptly recognized and corrected the low Unit 3 CST level.

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The safety significance of this observation was low; however, the slow response to an abnormal condition and reliance on assumptions were of concern to the inspectors. The control room staff was monitoring the air bubbling on a close-circuit television monitor and also did not react in a timely manner to determine the source of the air or act to secure it. The inspectors

observed less than adequate communications between the refueling floor and the control room. No core alterations or in-vessel work activities were in progress at the time of the event.

- **Refueling Bridge Mast Mis-alignment**

Less than adequate coordination and communication between personnel performing in-core fuel sipping resulted in the mis-alignment of the refueling bridge mast. Hoses connected to the fuel sipping hood became twisted around a vessel component and caused the mast to bend as it was being lowered. The inspectors noted that the individual who had been stationed to alert the bridge operators to such a situation did not recognize the interference and did not alert the bridge operator. PECO initiated a PEP report to review this event. The inspectors concluded that this event was not significant and also noted that no fuel handling evolutions were in progress at the time of the event.

- **Loss of Reactor Level Indication Events**

Less than adequate communications and coordination of the outage schedule resulted in two occurrences involving the loss of the upset range of reactor level indication during the removal of the reactor head. In both instances, technicians loosened the reference leg piping from the reactor head in preparation for head removal without informing the control room. Loosening the head piping resulted in draining of the reference leg to the transmitter. This caused the control room indications to fail upscale, and not indicate actual reactor vessel level. During both instances, reactor vessel water level was above the normal wide range level instrument band. With the upset range instrument failed upscale, the only valid reactor level indication was lost.

Reactor service personnel caused the first event by attempting to get ahead of the schedule; removing the piping without understanding the impact of their actions on plant parameters. The second event occurred due to mis-communication between the shift manager and the reactor services personnel during the head removal evolution. PECO initiated a PEP report to review both of these events.

These events were not safety significant since the reactor vessel water level was maintained high and other reactor vessel water level instruments needed for ECCS operability were still functional. The inspectors determined that both instances involved poor communications and coordination and an insufficient understanding by the technicians of the impact of their actions on the plant. The inspectors noted that the operations staff responded well to the first event, by lowering reactor level to within the range covered by the narrow range level instruments, and to the second event, by applying a correction factor to the indicated reactor vessel level.

- **Broken Fuel Rod**

Less than adequate communications between a vendor technician inspecting an irradiated fuel bundle and the reactor services supervisor occurred on September 23, 1994. A technician had disassembled one of the known leaking

fuel bundles to inspect the rods. A tie rod broke during reassembly of the fuel bundle. After the rod was contained, the technician informed an RP technician of the event, thus bypassing the reactor services supervisor. Additional time elapsed before the reactor services supervisor became aware of the event. PECO initiated a PEP report to review this event.

The inspector reviewed the video tape of the broken fuel rod inspection and determined that all nuclear material that had fallen from the rod when it broke was contained and accounted for. The technicians removed the fuel rod from the bundle for closer inspection after identifying it as cracked. The fuel rod broke during bundle reassembly as the nut was being replaced. PECO safely and appropriately secured the broken pieces inside the water rod of the bundle and stored the fuel bundle in the spent fuel pool.

2.1.3 Clearance and Tagging Issues

Clearance and tagging errors caused several unexpected plant events. The inspector reviewed these events and determined that their safety significance was low; however, these events did present unexpected and unnecessary challenges to the control room operators and plant staff, due to less than adequate self-check and attention-to-detail.

- **Loss of Shutdown Cooling Caused By Preventive Maintenance**

Unit 2 operators responded well to a loss of shutdown cooling (SDC) on September 21, 1994. The event occurred after an instrument and controls (I&C) technician lifted the neutral lead from a primary containment isolation system (PCIS) relay that broke the neutral loop to an in-series relay for the outboard SDC valve (MO-17) causing MO-17 to close. The operators immediately entered off-normal procedure, ON-125, "Loss of Shutdown Cooling," and stabilized the plant. SDC was restored within 19 minutes after the initial loss and reactor water temperature did not increase during the event. PECO made a four-hour notification to the NRC via the Emergency Notification System (ENS).

PECO was replacing relay 2-16A-K063 for the reactor water clean-up (RWCU) high flow isolation. The relay was one of nine relays that are electrically looped together on the neutral side of the relay coil and was the first relay in the loop from terminal board BB. The clearance properly de-energized the power source to the relay, but did not address the neutral lead. As the I&C technicians de-terminated the electrical leads from 16A-K063, the neutral loop was broken, de-energizing the remaining eight relays which included the 2-16A-K030 relay for MO-17 causing the SDC isolation.

PECO determined the cause of the event to be a less than adequate review during preparation of the clearance. The clearance writer failed to identify the looped neutral circuit on the wiring diagram and the technical reviewer failed to identify the neutral circuit due to inadequate training. Further, the removal of neutral leads was considered to be knowledge of the craft. As an interim corrective action, PECO recalled all work orders involving relay replacement to re-evaluate the clearances. Long term actions included

training of all clearance writers and technical reviewers in this area. The inspector reviewed PECO's actions and noted that no recurring events occurred.

- **Inability to Restart Shutdown Cooling**

On September 24, 1994, during a control room tour, the inspector noted that operators could not open the shutdown cooling injection valve, MO-25A, while attempting to return shutdown cooling to service. Investigation into the cause of MO-25A's failure to open indicted that a tagout had been previously applied to isolate the A train of core spray (CS) logic. This caused the low pressure coolant injection permissive relay to be deenergized thus preventing MO-25A from opening.

The inspector reviewed the associated clearance and found that it did not identify that the relay for the low pressure interlock on the residual heat removal (RHR) system would be affected by the deenergization of the CS logic. PECO addressed the problem and reestablished SDC.

- **Loss of Reactor Cavity Clarity**

During SDC operation an unexpected increase in RHR flow occurred and caused a loss of reactor vessel water clarity. The flow increased when the flow control valve (CV-2677D) to the 2D RHR heat exchanger drifted open following the application of a clearance that de-energized control power to the valve. The operators understood that the control power would be de-energized by the clearance, but assumed that the valve position would remain throttled open. The inspector and PECO determined that a note on a wiring diagram stating that the valve would fully open with control power de-energized was missed by the clearance writer and operators.

- **Insufficient Clearance Applied to the Turbine Building Closed Cooling Water**

The inspectors noted problems with restoring the non-safety related turbine building closed cooling water (TBCCW) and instrument air systems following the non-safety service water system outage. While all affected equipment was non-safety related, this event indicated problems with clearance and tagging, system inter-relationship knowledge, procedural adherence, and review of information tags prior to equipment operation. This event resulted in operation of the instrument air compressors without cooling water and subsequent automatic shutdown of two of the compressors on high temperature. The operators responded appropriately to the loss of the air compressors. PECO initiated a PEP review to investigate this event. The inspector had no further questions.

2.2 High Pressure Coolant Injection Valve Packing Leak - Unit 3

On September 24, 1994, the control room staff responded well to an unexpected increase in the Unit 3 drywell temperature and pressure. The operators promptly entered procedures OT-101, "High Drywell Pressure" and ON-120, "High Drywell Temperature," and were able to stabilize drywell pressure at approximately 0.6 psig by maximizing drywell cooling. The operators

determined that the pressure increase was due to a steam leak from the high pressure coolant injection (HPCI) system steam supply valve (MO-3-23-15). MO-3-23-15 is normally open to provide a steam supply flowpath to the HPCI turbine, and also has a safety function to shut for containment isolation. The operators shut and de-energized MO-3-23-15 to isolate the steam leak and declared the HPCI system inoperable, thus placing Unit 3 in a seven day TS shutdown action statement. Further actions to correct this problem are discussed in Section 4.4.

2.3 Torus Room Tour - Unit 3

The inspectors toured the Unit 3 torus room as part of the normal plant inspection. The housekeeping, material, and radiological conditions in the area were acceptable and properly posted.

2.4 Management Oversight of Plant Operations

The inspector attended numerous morning and plant operations review committee (PORC) meetings and the September 1994 Nuclear Review Board (NRB) meeting at PBAPS. The plant manager continued to use the morning meeting as a very useful tool for identifying follow-up items and equipment problems. Issues raised and discussed at length in this meeting included the failure of a emergency diesel generator (EDG) output breaker to re-close following tripping per a surveillance test and the failure of the 3D high pressure service water pump (HPSW). PECO continued to discuss potential radiological control problems identified by personnel contamination reports. PECO also started to use this meeting to allow distribution of PEP issues to the responsible department managers. This appeared to be a good method of letting all site directors know of the type of issues identified; however, the inspector found some variability as to the amount of discussion that took place on PEP issues.

The September 1994 NRB meeting focused on PBAPS activities. The discussions focused on Quality Assurance (QA) audits, Independent Safety Engineering Group (ISEG) reports, plant manager reports and review of LERs and NRC inspection reports. The NRB discussed the upcoming core shroud cracking inspection on Unit 2 and showed good safety insights. The NRB also showed concern that the NRC, not PECO, had to identify that chemistry technicians were not taking proper environmental monitoring samples of the Susquehanna River as required by TS. (Discussed in NRC IR 94-04).

2.5 Unified Log Update

PECO took good actions to address an inspector's concern over the use of the integrated control room log. Through comparison of the computerized log versus the official hard copy log, the inspector noted that the hard copy log did not include fourteen entries made during a four hour period. The inspector found that the missing entries were in the computer system, but were not printed out, since they were made after shift turnover. The inspector brought this discrepancy to the shift manager's attention who initiated a PEP review and a new printout of the log.

PECO performed an audit of the log as far back as August 23, 1994, and found 48 instances of missing entries. The results of the PEP investigation indicated that all entries were not made prior to the end of shift print out. Further, PECO identified that supervisors closing-out LCO entries were not entering the time of closure on the LCO close-out field causing the computer to enter a default time of midnight for that day. PECO changed the Operations Manual to require the previous days log to be printed at about 1:00 a.m., and reprinted all log entries from July 25, 1994, when the computerized log was officially implemented. PECO also implemented software program changes to properly close LCO entries. The inspector found these action acceptable.

2.6 Licensee Event Report Update

The inspectors reviewed the following Licensee Event Reports (LERs), finding them factual, and that PECO had identified the root causes, implemented appropriate corrective actions, and made the required notifications.

LER No.	LER Date	LER Title
2-94-008	8/3/94	Emergency Service Water Valve Closed and Left Unattended
2-94-006	8/4/94	Missed Fire Watch
2-94-007	8/10/94	Unit 2 Secondary Containment Breached to Fight Fire
3-94-003	8/11/94	High Pressure Coolant Injection System Inoperable during Maintenance Activities
3-94-004	9/24/94	High Pressure Coolant Injection Steam Supply Valve Leak

2.7 10 CFR Part 21 Report Update

PECO implemented a good program to review safety-related equipment deficiencies identified to them by manufacturers, under 10 CFR Part 21. This process used the station action request system to ensure that the proper personnel become aware of the issue and to ensure that adequate reviews and corrective actions are taken. The inspectors reviewed the actions taken on the following 10 CFR Part 21 reports, finding that PECO took proper corrective actions when the reports applied to PBAPS.

Date	Part 21 No.	Title/Resolution
4/30/91	93-016	ABB Current Transformer Cracking - PECO has implemented the inspection of this type current transformer into the preventive maintenance program. Presently, all switchgear, with the exception of two load centers scheduled for the fall of 1995, have been inspected. No discrepancies have been found.

3.0 SURVEILLANCE TESTING OBSERVATIONS (61726, 71707)

The inspectors observed conduct of surveillance tests (STs) to determine the use of approved procedures, the calibration of testing instrumentation, if qualified personnel performed the tests, and that test acceptance criteria were met. The inspectors verified that: STs were properly scheduled and approved by shift supervision prior to performance; control room operators were knowledgeable about testing in progress; and redundant systems or components were available for service, as required. The inspectors routinely verified adequate performance of daily STs including instrument channel checks, and jet pump and control rod operability tests. The inspectors found these activities to be acceptable.

3.1 Containment Leakrate Surveillance Testing

During the outage the inspector observed several local leak rate tests (LLRTs). In all cases the personnel conducting the testing were knowledgeable and conducted the testing in accordance with procedures. The inspector also reviewed and found acceptable a PECO discussion not to conduct as-found local leak rate tests on valves that PECO was scheduled to work on during the outage. PECO QA conducted a detailed review of the LLRT program and conducted an informative exit meeting. The audit identified several issues that line management committed to resolve.

3.2 Undervoltage Testing - Unit 2

The inspectors observed the undervoltage testing conduced on 4160 volt bus E22. The individuals involved in the testing, including operators, maintenance technicians, and engineers, performed well using good communication and proper techniques to complete the testing. The inspector reviewed the surveillance test procedure finding that all TS surveillance requirements were tested.

During a subsequent test of the E-12 bus undervoltage relays and tripping logic, the E42 diesel generator output breaker failed to reshut following opening. PECO removed the breaker and re-tested the newly installed breaker satisfactory. PECO found that the breaker trip mechanism did not quickly reset, preventing subsequent re-closure. PECO engineering and the PECO corporate laboratory examined and reviewed this breaker's failure to operate and determined that hardened grease caused binding of the trip mechanism. The inspectors will review PECO's corrective actions in a subsequent report.

3.3 Core Shroud Inspection - Unit 2

During the Unit 2 outage PECO conducted an ultrasonic inspection of the reactor vessel core shroud accessible weld areas. These examinations identified cracking of a similar nature to that found at Unit 3, but of much less magnitude. Based on an engineering analysis of the examination results, PECO determined that the Unit 2 shroud was structurally sound and that no actions were required to ensure its stability over the next operating cycle.

PECO presented the preliminary examination results to the NRC staff prior to unit restart. Final examination documentation will be submitted to the NRC staff for review in accordance with NRC Bulletin 94-01.

3.4 Station Blackout Modification Acceptance Test

During the period, PECO completed the installation of an electrical power supply from the Conowingo Dam Generating station to the PBAPS 13 kV switchgear. PECO has submitted a TS amendment to allow use of this supply as an alternate AC power source. The inspector observed a portion of the modification acceptance testing of this power feed. This included aligning the source to the station and operating an RHR pump. This testing demonstrated that the system could be used to supply power to a 4.1 kV safety-related switchgear. Further, the data accumulated during the testing will be used by PECO engineering to validate the assumptions needed for the source to supply an RHR and HPSW pump at each unit, and all the 480 volt emergency switchgear in the event of a loss of offsite power and the failure of all the EDGs to start (i.e., station blackout).

4.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703)

The inspectors observed portions of ongoing maintenance work to verify proper implementation of maintenance procedures and controls. The inspectors verified that PECO adequately implemented administrative controls including blocking permits, fire watches, and ignition source and radiological controls. The inspectors reviewed maintenance procedures, action requests (AR), work orders (WO), item handling reports, radiation work permits (RWP), material certifications, and receipt inspections. During observation of maintenance work, the inspectors verified appropriate Quality Verification (QV) involvement, plant conditions, TS LCOs, equipment alignment and turnover, post-maintenance testing and reportability review. The inspectors found the PECO's activities to be acceptable.

4.1 E-12/E-32 Bus Outages

The inspectors observed good work practices and control during preventive and modification work conducted on the E12 and E32 4kV switchgear equipment. The scheduling and control of the work activities was good, and proper precautions and alternate power supplies were properly implemented.

4.2 Residual Heat Removal System Injection Valve (MO-25B) Unit 2

The inspector noted good coordination between the maintenance and engineering departments during activities performed on a Unit 2 RHR system injection isolation valve (MO-25B). PECO identified a slight misalignment between the valve yoke and body which caused interference between the valve stem and bonnet during operation. PECO decided to enlarge the bonnet bushing area to alleviate the stem-to-bonnet interference, and to replace the yoke during the next Unit 2 refueling outage.

PECO adequately developed, documented, and sequenced the repair method in a non-conformance report (NCR). The inspector observed selected MO-25B field maintenance activities, noting good control, in accordance with the NCR disposition. Additionally, the NCR provided adequate justification for the activities and addressed potential concerns regarding the integrity of the valve's stem, bonnet, and yoke. The inspector noted that the valve vendor reviewed and concurred with the NCR disposition.

The inspector noted no problems, concluding that the engineering disposition and the field maintenance activities were performed well.

4.3 Failed Reactor Building Ventilation Damper - Unit 3 (Update) Unresolved Item 94-10-01; Solenoid Valve Failures

The inspector determined that PECO responded well on August 31, 1994, when the reactor building ventilation supply isolation damper (AO-30457) failed to shut during a transfer of the "B" reactor protection system to its alternate power source. AO-30457 should have shut when its solenoid control valve deenergized on the resulting Group III isolation. This would have allowed the standby gas system to establish a negative pressure in the secondary containment. PECO promptly declared the secondary containment inoperable and initiated a plant shutdown in accordance with TS 3.7.C.1.

PECO performed troubleshooting and determined that the normally energized ASCO solenoid valve, which directed operating air to the damper, failed to reposition when deenergized. PECO replaced the solenoid valve, successfully tested AO-30457, and exited TS 3.7.C.1. The inspector concluded that PECO responded promptly and appropriately to this event.

The inspectors noted that similar normally energized ASCO solenoid valves have failed to reposition in the ESW system. Those failures were discussed in Inspection Report 94-10, Section 5.2. The inspectors continue to review PECO's corrective actions to address these failures.

4.4 High Pressure Coolant Injection Steam Packing Leak - Unit 3

PECO performed well in developing plans to address packing leakage from the HPCI inboard steam isolation valve (MO-2-23-15). This included development of a special procedure to backseat the valve to isolate the leak by applying short electrical open command signals to the motor operator contactor. This allowed the valve to coast into its backseat to minimize mechanical stresses. Prior to backseating the valve, the PORC approved a 10 CFR 50.59 safety review to ensure that this activity would not introduce an unreviewed safety question. The inspectors reviewed the special procedure, the safety evaluation, and attended the PORC meeting and determined that PECO focused on performing this evolution safely.

On September 28, 1994, PECO backseated MO-3-23-15 and successfully stopped the steam leak. The inspectors noted that the job pre-brief and the evolution were performed well. After backseating the valve, PECO performed the required

valve timing test and demonstrated that the valve was capable of meeting its isolation time limits from the backseated position. PECO management indicated that they planned to repair the valve during the next Unit 3 shutdown.

4.5 3D High Pressure Service Water Pump Failure - Unit 3

PECO responded well and identified the cause of a September 7, 1994, motor bearing failure on the 3D HPSW pump. While running the pump, operators in the area noticed smoke coming from the upper bearing after responding to a control room high temperature alarm. The operators left the area and directed that the control room secure the pump. The fire brigade responded well to the indication of the fire, including proper use of self contained breathing apparatus during a room entry and proper preparation for smoke removal. After the pump was secured, the fire brigade noted that the smoke generation had stopped, and determined that there was not a fire condition.

Plant management ensured that aggressive action was taken to determine the cause of the pump motor bearing failure. Site system engineering, maintenance, and PECO corporate testing laboratory personnel, performed well during the pump removal and disassembly. PECO concluded that the deep draft pump line shaft couplings had loosened causing the motor and pump damage. Normal pump rotation causes the line shaft couplings to tighten; reverse rotation would cause the coupling to loosen and lengthen the overall pump shaft. PECO determined that the pump shaft had turned backwards, following securing the D pump with the B pump in operation, due to check valve leakage. This reverse rotation cause the couplings to loosen and lengthen the pump shaft. The lengthened pump shaft then caused an upward thrust on the upper bearing and a downward force on the pump internals resulting in the damage to the motor and pump.

PECO continues to review this issue and to develop corrective actions. The inspector will review these actions in a subsequent report.

4.6 (Closed) High Pressure Coolant Injection Motor Starting Relays, Unresolved Item 93-25-02

PECO properly implemented a modification to the DC motor controllers for the HPCI systems of both units in April and May, 1994. PECO removed the time armature (TA) resistance relays from all affected DC motor controllers under modification package P00259. Four previously reported events had been caused by the mis-operation of this relay, that was initially installed in all HPCI DC motor controllers to limit the starting current surge. PECO had previously removed the starting resistors under an earlier modification because the actuators did not develop sufficient thrust and torque to perform their safety function under worst case DC power distribution and environmental condition; however, the TA relays were not removed as part of the earlier modification.

The resident staff reviewed the four instances where HPCI system components failed to operate on-demand because of mis-operation of the TA relay since October 1992. In two cases, the HPCI system injected following reactor scrams as designed, but failed to restart after the system had been secured. The

inspectors reviewed the safety significance of these mis-operations at the time of the scrams and determined it to be low since operators would not have secured the system if operation was necessary.

The other two cases involved valve failures to open, during surveillance testing. The inspectors determined that these events were not safety significant since they were identified during surveillance testing and since the automatic depressurization system and low pressure coolant injection systems were operable at the time. Further, for each instance PECO took appropriate actions to correct the individual problems, inspected the other TA relays to ensure that the auxiliary contacts would function, and properly reported the events to the NRC.

The inspectors reviewed the modification package and engineering change requests and discussed the effects of the TA relay removal on the individual components and DC distribution system with the system manager. The inspector determined that the modification sufficiently corrected the component failure problem. The inspector has observed no further failures since implementation of the modification. This item is closed.

5.0 ENGINEERING AND TECHNICAL SUPPORT ACTIVITIES (37551)

The inspectors routinely monitor and assess licensee support staff activities. During this inspection period, the inspectors focused on the activities discussed below.

5.1 Outage Modification Packages Review - Unit 2

- **Modification 5195**

The inspector reviewed the modification package (Mod 5195) for the installation of a refueling level indication and concluded that PECO performed a good analysis to revise reactor level indication during refueling operations. Mod 5195 changed the function of reactor level transmitter (LT)-2-2-3-70 from providing indication of Shutdown Level (-78" to -178") to providing Refueling Level indication (0" to +500"). The shutdown level transmitter previously tied into the fuel-zone instrument piping and provided erratic indication during recirculation pump operation. The new instrument will be a pressure transmitter attached to the narrow range instrument process piping.

The new level instrument will provide a permanent level indication that will not require a temporary set-up during refueling outages. During this outage, and in the past, reactor level indication above +60" was temporarily lost in the control room due to the removal of the reactor vessel head which affected the level transmitters reference leg. A temporary reference leg had to be attached and backfilled, and the instrument calibrated, in order to maintain accurate level indication in the control room.

The inspector concluded that the design input documentation and safety evaluation were of high quality. Additionally, the inspector determined that this modification should be an effective improvement for continuous monitoring of reactor level and should prevent recurrence of the loss of level events discussed above (Section 2.1.2).

- **Modification 5414**

The inspector reviewed the applicable engineering documentation and concluded that PECO performed a good analysis and review of Modification 5414 for the installation of the 4kV bus off-tie breaker transfer circuitry. The modification improves the design in three areas: 1) improving the source breaker logic to prevent repeated cycling of the source breakers due to a combination of a marginal grid voltage and a loss of coolant accident (LOCA) load sequence; 2) modifying the core spray logic to prevent the loss of two 4kV buses caused by a degraded grid condition coincident with a single failure in the initiation logic of core spray; and 3) adding cross divisional LOCA initiation signals to both the 4kV emergency switchgear transfer logic and emergency diesel generator start circuits.

The inspector concluded that the design input documentation and safety evaluation were of high quality.

5.2 Chronic Equipment List Review

The inspector found that PECO effectively used the Chronic Equipment/System Problem list to prioritize, track, and monitor corrective actions for long term non-safety and safety-related equipment reliability problems. The list was broker down into two sections: Section A; problems that still need engineering review to determine needed actions, and Section B; problems awaiting action implementation. The issues in the September 13, 1994, list did not pose any threat to nuclear safety. Of the 17 items in Section A, and 10 items in Section B, 11 and 4, respectively, did not deal with components or systems that related to the safe nuclear operation of either unit. These items dealt with non-safety components, which would only affect station electrical generation reliability, not nuclear safety.

Review of the other 6 Section A items found that PECO was taking appropriate action to assess and develop plans to address the issues. Further, the inspector assessed that none of these issues represented a reduction in systems or indications necessary for operators to safely operate the plant. These issues included:

- Problems with control rod position indication reliability due to electrical connector problems. If the position indication is lost during operation, operators have an appropriate procedure to correct the problems.

- HPSW pump problems. PECO experienced problems with these deep draft pumps in 1993, and again in 1994, as discussed in Section 4.5 above. The inspector assessed that PECO has identified the issues to improve the operation and reliability of the HPSW system. Further, the four

HPSW pumps installed at each unit, and the installed capability to cross tie the two units HPSW systems, provides reliable and redundant cooling water sources in accordance with plant TS.

- Reliability of source range and intermediate range nuclear monitoring instruments. This issue related repeated instances of instrument failures during shutdown conditions. Such failures cause the instruments to fail in a safe condition (i.e., initiate a partial reactor scram). This is an issue since operators need to respond to such failures, but is insignificant with respect to nuclear safety.

- Traversing incore probe detector problems. These detectors are used to calibrate the nuclear instruments during reactor operation. Failure of a detector is detectable and addressed by procedures.

- Inservice Testing Failures. This issue deals with establishment of new criteria for the testing of safety related pumps, to ensure that pumps are not declared inoperable due to faulty test data, when actual pump degradation has not occurred. This is not a safety significant issue, since declaring a pump inoperable requires operators to take conservative actions in accordance with plant TS.

- Failure of the Unit 3 A RHR injection valve (MO-25A). This issue deals with PECO's actions to address concerns due to the 1993 failure of the valve. This valve failure was the subject of an NRC violation. Further, the inspectors have observed that PECO has taken good actions to address the identified problems. This issue is not safety significant.

Of the 9 issues on the Section B list, 5 dealt with safety-related or important systems, representing no threat to nuclear safety. PECO has taken appropriate actions to plan for and prioritize corrective actions. The issues were:

- HPSW radiation monitor unreliability. PECO installed a modification to enhance the sampling systems and is in the process of completing testing. This system ensures that the water flow from the RHR heat exchanger is monitored. Further, operators have control room indication of the operability of these instruments, and, if they become inoperable, will perform TS required alternate sampling methods.

- HPCI TA relay issue. This issue resulted from numerous failures of these relays during HPCI operation as discussed in Section 4.6 above. PECO has taken aggressive actions to address this issue, planning a modification to upgrade the HPCI control components.

- Instrument nitrogen compressor and dryer problems. This system provides a constant source of nitrogen to components in the drywell. In all cases, the safety-related components supplied have installed accumulators which provide a stored supply in the event of a compressor problem. Further, operation procedures provide instructions on

switching compressors and on the need to shutdown the units in accordance with TS, if an adequate nitrogen supply can not be maintained.

- HPCI equipment problems. These problems dealt with the reliability of the HPCI system and PECO's planned improvements. The improvements include enhancing the lube oil system and associated components and instrumentation. These efforts appear appropriate and currently do not affect the safe operation of HPCI.

- Containment atmospheric dilution (CAD) valve problems. In the past, PECO experienced problems with CAD valves not passing the required flowrate. These issues have been observed during CAD operation and corrected.

In summary, PECO uses these lists to focus long term engineering and management attention to correct and prioritize known reliability problems, with both safety related and non-safety related equipment and systems. The inspectors were aware, through day to day interaction, of all the issues. Further, the inspectors found that there were no conditions which represented a specific safety concern.

5.3 Temporary Change Review

During review of the E-32 bus outage the inspector identified that PECO performed a temporary procedure change (TC) to allow the emergency cooling water (ECW) pump to act as a spare emergency service water (ESW) pump. PECO conducted this TC because deenergization of the E-32 bus would cause the B ESW pump and the B ESW booster pump to be inoperable due to loss of power, thus the only pump available to supply EDG and ECCS cooling loads would have been the A ESW pump.

The inspector found that the flow path established by the TC would have provided adequate cooling to the EDGs and the ECCS loads in the event of a design basis accident and a single failure causing the loss of the A ESW pump; however, the inspector questioned whether the TC changed the intent of the procedure, based on a major change in the flow path. The initial intent of the procedure based on the procedure purpose statement was to allow the ECW pump to function as an ESW pump if an ESW pump was not available. The body of the procedure provided instructions to use the ECW pump and an ESW booster pump to supply cooling water from the emergency cooling tower to the EDGs and ECCS loads and back to the ECT, with the ESW discharge valve to the river (MO-498) closed. Because an ESW booster pump was not available, the TC allowed the ECW pump to supply cooling loads and discharge directly to the river through MO-498, which would cause ECT level to lower. The procedure specified that a HPSW pump would be used in accordance with an approved procedure, to maintain ECT level.

PBAPS administrative procedure A-3, "Temporary Changes to Procedures," states that a change of intent is "any change in the function or conceptual method of the activity". This procedure then uses a check list of the types of changes that may or may not be made with a TC. The inspector was concerned that PBAPS

procedures for TCs did not identify a major change in a system flow path as a possible intent change. This was an issue since a change in flow path could allow a system to be operated outside its design requirements in an unanalyzed condition contrary to 10CFR 50.59.

PECO agreed with the inspector that this TC to AO-48.2, "Using the Emergency Service Water Pump as an Emergency Service Water Pump," was questionably an intent change and stated that they would be conducting additional training on this area and review the administrative procedures. The inspector considered this issue unresolved pending review of PECO's actions. **(Unresolved 94-21-01)**

6.0 PLANT SUPPORT (71750)

6.1 Radiological Controls

The inspectors examined work in progress in both units to verify proper implementation of health physics (HP) procedures and controls. The inspectors monitored the ALARA (As Low As Reasonably Achievable) program implementation, dosimetry and badging, protective clothing use, radiation surveys, radiation protection instrument use, handling of potentially contaminated equipment and materials, and compliance with radiation work permit (RWP) requirements. The inspectors observed that personnel working in the radiologically controlled areas met applicable requirements and were frisking in accordance with HP procedures. During routine tours of the units, the inspectors verified that a sampling of high radiation area doors were locked, as required. All activities monitored by the inspectors were found to be acceptable.

6.2 Physical Security

The inspectors monitored security activities for compliance with the accepted Security Plan and associated implementing procedures. The inspectors observed security staffing, operation of the Central and Secondary Access Systems, licensee checks of vehicles, detection and assessment aids, and vital area access to verify proper control. On each shift, the inspectors observed protected area access control and badging procedures. In addition, the inspectors routinely inspected protected and vital area barriers, compensatory measures, and escort procedures. The inspectors found PECO's activities to be acceptable.

7.0 MANAGEMENT MEETINGS (71707,30702)

The resident inspectors provided a verbal summary of preliminary findings to the station management at the conclusion of the inspection. During the inspection, the inspectors verbally notified PECO management concerning preliminary findings. The inspectors did not provide any written inspection material to the licensee during the inspection. PECO did not express any disagreement with the inspection findings. This report does not contain proprietary information.