November 4, 2003

Mr. John L. Skolds
President and CNO
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: PEACH BOTTOM ATOMIC POWER STATION - NRC INTEGRATED INSPECTION REPORT 05000277/2003004 AND 05000278/2003004

Dear Mr. Skolds:

On September 27, 2003, the US Nuclear Regulatory Commission (NRC) completed an inspection at the Peach Bottom Atomic Power Station, Units 2 and 3. The enclosed integrated inspection report documents the inspection findings, which were discussed on October 16, 2003, with Mr. Rusty West and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one finding related to a long-standing condition adverse to quality associated with the Unit 2 steam tunnel temperatures. This finding is unresolved pending completion of a final risk significance determination. This finding does not present an immediate safety concern since Exelon has taken compensatory measures while it implements long-term corrective measures.

In addition, the inspectors identified three non-cited violations of very low safety significance (Green) and one non-cited violation of severity level IV associated with lack of records to support changes made to the emergency plan. Licensee-identified violations that were determined to be of very low safety significance are listed in Section 4OA7 of this report. These issues were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they have been entered into your corrective actions program, the NRC is treating these issues as non-cited violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny any of these non-cited violations noted in this report, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Peach Bottom facility.

Since the terrorist attacks on September 11, 2001, NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of TI 2515/148 was completed at all commercial power nuclear power plants during calender year 2002 and the remaining inspection activities for Peach Bottom were completed in June 2003. The NRC will continue to monitor overall safeguards and security controls at Peach Bottom.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

If you have any questions, please contact me at 610-337-5209.

Sincerely,

/RA/

Mohamed Shanbaky, Chief
Projects Branch 4
Division of Reactor Projects

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

Enclosure: Inspection Report 05000277/2003004 and 05000278/2003004
w/Attachment: Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos.:	50-277, 50-278
License Nos.:	DPR-44, DPR-56
Report No.:	05000277/2003004 and 05000278/2003004
Licensee:	Exelon Generation Company, LLC Correspondence Control Desk 200 Exelon Way, KSA 1-N-1 Kennett Square, PA 19348
Facility:	Peach Bottom Atomic Power Station Units 2 and 3
Location:	1848 Lay Road Delta, Pennsylvania
Dates:	June 29, 2003 - September 27, 2003
Inspectors:	C. Smith, Senior Resident Inspector A. McMurtray, Senior Resident Inspector (Former) M. Buckley, Senior Resident Inspector (Temporary) J. Caruso, Senior Operations Engineer H. Eichenholz, Senior Reactor Inspector D. Florek, Senior Project Engineer R. Nimitz, Senior Health Physicist J. Schoppy, Senior Reactor Inspector S. Iyer, Reactor Inspector N. McNamara, Regional Emergency Preparedness Inspector D. Schroeder, Resident Inspector B. Welling, Resident Inspector
Approved by:	Mohamed M. Shanbaky, Chief Projects Branch 4 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000277/2003-004, 05000278/2003-004; 06/29/2003 - 09/27/2003; Peach Bottom Atomic Power Station, Units 2 and 3; Licensed Operator Requalification, Operability Evaluations, and Emergency Preparedness.

The report covered a 13-week period of inspection by resident inspectors, regional inspectors, and announced inspections by senior reactor inspectors, a senior health physicist, a senior operations engineer, and a regional emergency preparedness inspector. One Severity Level IV non-cited Violation (NCV), three Green non-cited violations (NCVs), and one unresolved item were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspector identified a non-cited violation (NCV) of 10 CFR 55.53(f)(2) regarding the licensee's method used to reactivate senior operator licenses to support refueling. The operators were reactivated without the required direct supervision being present during the shift under-instruction time.

  This finding is more than minor but of very low safety significance because it is similar to example 2h in Appendix E of MC 0612. The performance deficiency is related to operator license conditions. The performance deficiency indicates more than 20% of the senior operator license reactivations to support refueling operations did not meet the requirements of 10 CFR 55.53(f)(2). Accordingly, the performance deficiency was determined to be of very low safety significance. (Section 1R11)

- Green. The inspectors identified a non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, because Exelon did not adequately correct a significant condition adverse to quality, identified during a December 21, 2002 scram, associated with the inoperabiity of the Unit 2 reactor core isolation cooling (RCIC) pump in the automatic flow control mode. As a result of not adequately correcting this significant condition adverse to quality, the Unit 2 RCIC pump was not able to deliver the Technical Specification required 600 gpm flow rate into the reactor vessel in the automatic flow control mode during a July 22, 2003 scram.

  This finding is considered more than minor because it is associated with the design control attribute of the Mitigating Systems Cornerstone and adversely affects the objective, in that, the capability of RCIC was degraded to respond to initiating events to prevent undesirable consequences. This finding is of very low safety significance (Green) using Phase 1 of the Significance Determination Process (SDP) for Reactor Inspection Findings for At-Power Situations. This issue is of very low safety significance because there was no loss of safety function for RCIC and the finding is not risk significant because of seismic, flood, fire or severe weather. Unit 2 RCIC pump flow was high enough (i.e., a nominal flow rate of approximately 560 gpm), in the automatic flow control mode to maintain reactor vessel water level. Additionally, RCIC pump flow in the manual flow control mode was able to reach 600 gpm. (Section 1R15)

- Green. The inspectors identified a non-cited violation (NCV) of Condition 2.C.4 of the Unit 3 operating license. This finding occurred because Exelon instrumentation and control (I&C) technicians did not follow work order instructions for conducting testing on the Unit 3 high pressure coolant injection (HPCI) alternate control station following maintenance activities. Consequently, the HPCI alternate control station power supply remained de-energized for approximately nine days, resulting in the control station being inoperable for safe shutdown of Unit 3 during specific scenarios, a violation of Condition 2.C.4 of the Unit 3 operating license.

  This finding is more than minor because it was associated with the human performance attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective. Operations did not have the ability to use the alternate control station for operation of HPCI and lost the ability to monitor some important reactor parameters. A Phase 3 SDP was performed due to the results of the Phase 2 determination because in case of fire in the control room or emergency shutdown panel, level control using HPCI at the control station was unavailable and the loss of reactor instrumentation at the control station would have affected operators' ability to perform depressurization and containment cooling functions. The Phase 3 SDP determined this issue to be of very low safety significance.

  A contributing cause of the Inoperable HPCI alternative control station was related to the Human Performance cross-cutting area. Specifically, I&C technicians did not follow procedures to perform the post-maintenance test specified in a maintenance work order. As a result, the control station was returned to service while in a degraded condition and was unavailable for operation of HPCI and monitoring of important reactor parameters for safe shutdown of Unit 3 in certain fire scenarios. (Section 4OA5)

- TBD. The inspector identified an unresolved item related to 10 CFR 50, Appendix B, Criterion 16. During the period of July 2001 through July 2003, Exelon did not adequately correct a condition adverse to quality, specifically a high Unit 2 steam tunnel temperature condition that was not representative of a steam leak. Consequently, on July 22, 2003, following a turbine trip and scram of Unit 2, a high main steam tunnel temperature condition, that was not representative of a steam leak, caused all main steam isolation valves to close resulting in a loss of the normal heat sink and reactor feed water system. The safety significance of this finding is not yet determined through the Significance Determination Process, but is known to be at least greater than minor. This is an unresolved item (URI) pending completion of the Significance Determination Process (SDP).

This finding is greater than minor because the issue is associated with the equipment performance attribute of the Mitigating Systems Cornerstone and adversely affects the cornerstone objective of availability of systems that respond to initiating events to prevent undesirable consequences. MSIV closure on a high main steam tunnel temperature condition, that was not representative of a steam leak, had the undesirable consequence of removing the normal source of feed water and the normal heat sink from the reactor and complicated the operator actions required to place the reactor in a safe shutdown condition. The finding is also associated with the equipment performance attribute of the Initiating Events cornerstone and adversely affects the objective of limiting the likelihood of those events that upset plant stability. A high steam tunnel temperature condition that is not representative of a steam leak would remove the normal source of feed water and heat sink and cause a reactor scram. (Section 1R15)

Miscellaneous

- SL-IV. The inspector identified a Severity Level IV non-cited violation of 10 CFR 50.54(q). During the implementation of a new Standard Emergency Plan, Exelon did not retain a record that determined whether a decrease-in-effectiveness had or had not occurred when Exelon generated the new Standard Emergency Plan that deleted portions of the previous Combined Limerick/Peach Bottom Emergency Plan.

  Changing emergency plan commitments without documentation impacts the NRC's ability to perform its regulatory function and is, therefore, processed through traditional enforcement as specified in Section IV.A.3 of the Enforcement Policy, issued May 1, 2000 (65 CFR 25388). According to Supplement VIII of the Enforcement Policy, this finding was determined to be a Severity Level IV because it involved a failure to meet a requirement not directly related to assessment and notification. (Section 1EP4)

B. Licensee Identified Findings

Violations of very low safety significance, which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 2 began this inspection period operating at approximately 100 percent power. On July 22, 2003, an automatic reactor shutdown occurred due to generator lockout from foreign material causing a short in the bus duct. Unit 2 returned to 100% power on July 29, 2003. On September 15, 2003, Unit 2 automatically shutdown from 100% power due to a loss of offsite power caused by electrical grid problems. Unit 2 was returned to 100% power on September 25, 2003, and operated the remainder of the period at or near full power.

Unit 3 began this inspection period operating at approximately 100 percent power. On August 14, 2003, the fifth stage feedwater heaters were removed from service for end of cycle coastdown. The fourth stage feedwater heaters were removed from service on August 24, 2003. On September 15, 2003, Unit 3 automatically shutdown from 91% power due to loss of offsite power caused by electrical grid problems. Unit 3 remained shutdown for refueling outage 3R14 for the remainder of the period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed Exelon's severe weather preparations for Hurricane Isabel. The inspectors used AG-108, Rev 11, "Preparation For Severe Weather" to review and evaluate the station's preparations for the weather conditions caused by Hurricane Isabel during September 19 and 20, 2003. During these reviews, the inspectors reviewed the removal of any critical equipment for planned maintenance, preparations for Unit 2 startup and the possible impact on plant risk with severe weather conditions. Unit 2 and Unit 3 were not operating during the severe weather experienced on September 19 and 20. This inspection activity represented one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04Q)

a. Inspection Scope

Partial System Walkdowns. The inspectors performed partial system walkdowns during this inspection period to verify system and component alignments and note any discrepancies that would impact system operability. The inspectors verified selected portions of redundant or backup systems/trains were available while a system was out-of-service. The inspectors reviewed selected valve positions, electrical power availability, and the general condition of major system components. This inspection activity represented four samples. The walkdowns involved the following systems:

- 3B residual heat removal during 3A residual heat removal planned maintenance
- Emergency diesel generators during E2 and E4 diesel generator mini outage
- Unit 3 high pressure coolant injection (HPCI) during Unit 3 reactor core isolation cooling (RCIC) mini outage
- Alignment check of reactor core isolation cooling (RCIC) restoration after post-maintenance testing

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q)

Routine Plant Area Tours

a. Inspection Scope

The inspectors reviewed the Fire Protection Plan, Technical Requirements Manual (TRM), and the respective Pre-Fire Action Plan procedures to determine the required fire protection design features, fire area boundaries, and combustible loading requirements for the areas examined during this inspection. The inspectors then performed walkdowns of the following areas to assess control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and any related compensatory measures. Documents reviewed during the inspection are listed in the Attachment. This inspection activity represented ten samples. The fire areas included:

- Unit 2 recirculation motor generator set room
- Unit 3 reactor building closed cooling water heat exchanger, pump area
- Emergency diesel generators 1, 2, 3, 4 & cardox system
- Unit 2 standby liquid control (SBLC) & N_2 compressor area
- Unit 3 electro-hydraulic control sump room, pumps & valve area
- Unit 3 standby liquid control (SBLC) & N_2 compressor area
- Unit 3 refuel floor (reactor building 234' elevation)
- Unit 3B residual heat removal pump room
- Unit 2A residual heat removal pump room
- Standby gas treatment fan room

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

1. Review by Regional Specialist (71111.11B)

a. Inspection Scope

The inspection activities were performed using NUREG 1021, Revision 8, Supplement 1, “Operator Licensing Examination Standards for Power Reactors,” Inspection Procedure Attachment 71111.11, “Licensed Operator Requalification Program,” Appendix A “Checklist for Evaluating Facility Testing Material.” License reactivations for the past two year requalification program cycle were reviewed for conformance with the requirements of 10 CFR 55.53 (f)(2).

b. Findings

Introduction

Green. A non-cited violation of 10 CFR 55.53(f)(2) was identified regarding the licensee’s method used to reactivate senior operator licensees to support refueling. The operators were reactivated without the required direct supervision being present during the shift under-instruction time. The Limited Senior Reactor Operator (LSRO) Requalification Program for Fuel Handlers is a dual site operator license program that applies to both Limerick and Peach Bottom sites.

Description

An unresolved item (URI 50-352; 50-353/02-04-01 and URI 50-277; 50-278/02-04-01) was identified during the biennial Licensed Operator Requalification Program inspection conducted the week of May 20, 2002 and documented in report 50-352; 50-353/02-04-01 and 50-277; 50-278/02-04-01. The Limited Senior Reactor Operator (LSRO) Requalification Program for Fuel Handlers is a dual site operator license program that applies to both Limerick and Peach Bottom sites. The methods and standards used at Limerick and Peach Bottom to re-activate LSRO licensees did not meet the requirements of 10 CFR 55.53(f)(2). 10 CFR 55.53(f)(2) requires, in part, that the LSRO stand one shift under-instruction, under the direction of a senior operator, and in the position to which the individual will be assigned. The site practice in the period of 1993-2002 had been to have LSRO licensees stand one 8 or 12 hour shift under-instruction watch that consisted of checking in with the shift manager, spending some time in the main control room reviewing refueling related instrumentation and plant status, reviewing the applicable unit Limiting Condition for Operation (LCO) log, and attending shift briefings. The remainder of the shift time was spent on the refueling floor performing self-directed review and study of procedures, as well as walk-downs and familiarity with equipment. Therefore, the licensee’s procedure guidance and practices for re-activating LSRO licenses provided very little direct SRO oversight or feedback while the LSRO was completing the required one shift of under-instruction requirement. In addition, the inspector noted at the time of this inspection that there were three different procedures (A-C-10, Revision 3, “Operator Licenses”; OP-AA-105-102, Revision 1, “NRC Active License Maintenance”; TQ-AA-131, Revision 0, “Senior Reactor

Operator-Limited Requalification Training") that provided conflicting guidance/direction for maintaining and re-activating an LSRO license.

This issue was forwarded to the Office of Nuclear Reactor Regulation (NRR) for further guidance on whether Exelon's practice met the intent of the regulation, and is summarized below:

> Ideally the "under-direction" watch performed for the purpose of reactivating an LSRO license (or a full-scope SRO license for refueling operations alone) should be performed primarily in the fuel handling area during refueling operations (i.e., at a time when the presence of a senior operator is required pursuant to 10 CFR 50.54(m)(2)(iv)). This would clearly meet the intent of 10 CFR 55.53(f)(2), which requires the licensee to complete one shift of shift functions under the direction of a senior operator in the position to which the licensee will be assigned, and the 10 CFR 55.4 definition of *actively perform the functions of a senior operator*, which requires the licensee to fill a position on the shift crew that requires the individual to be licensed and to carry out and be responsible for the duties covered by that position.
>
> However, given the infrequency and short duration of shift functions that require the presence of an (L)SRO on the refueling floor, it may not always be practical for a facility licensee to delay its (L)SRO reactivations until those shift functions are actually underway. In those instances, NRR has concluded that the facility licensee can satisfy the intent of the regulation by implementing a reactivation program that specifies, in detail, the refueling tasks, activities, and procedures that an (L)SRO must satisfactorily complete or simulate (e.g., by using dummy fuel assemblies) in order to demonstrate watch-standing proficiency. Moreover, such a program shall exercise positive control to ensure that the required tasks, activities, and procedures are completed within a reasonable period of time (ideally, no more than one week) before the (L)SRO is assigned to supervise refueling shift functions.
>
> The NRC's requirements regarding the conduct of under-instruction or training watches are contained in 10 CFR 55.13, which allows trainees to manipulate the controls of a facility "under the direction and <u>in the presence of</u> a licensed operator or senior operator..." [emphasis added] This position is also evident in the responses to Questions #252 and #276 in NUREG-1262, "Answers to Questions at Public Meetings Regarding Implementation of Title 10, Code of Federal Regulations, Part 55 on Operators' Licenses," which indicate that a trainee's activities are to be <u>closely monitored</u> by the responsible person.
>
> On reviewing the September 15, 1993, letter from NRR regarding the licensee's reactivation program, NRR noted that the staff had recommended that the training procedure explicitly capture the facility licensee's past practice and the 10 CFR 55 requirement for the reactivation tasks to be performed under the direction of active SROs. Moreover, Section 8.7 of the LSRO program plan attached to the letter clearly reflected the licensee's expectation that the

> reactivation must be performed "under the direction of an active SRO or LSRO" and, for one activity, clarified that it could be performed more than 72 hours prior to the start of core alterations as long as it was done "in the company of an active LSRO or SRO."
>
> Based on the above, it appears that the current LSRO reactivation practices at Limerick and Peach Bottom do not meet the intent of the NRC's regulations or the facility licensee's previously approved program plan. To properly reactivate an (L)SRO license per 10 CFR 55.53(f), the individual should stand watch under the direction and in the presence of an active SRO or LSRO who will directly oversee the trainee's activities, provide feedback as appropriate, and enable an authorized representative of the facility licensee to certify that the operator's qualifications are current and valid. Permitting the trainees to perform self-directed activities on the refueling floor eliminates the opportunity for meaningful feedback, thereby casting doubt on the validity of the resulting certification."

Consequently, the inspector determined that a performance deficiency existed and it was a violation of NRC requirements.

Analysis

The performance deficiency is the method used at Limerick and Peach Bottom in the period 1993 - 2002 to re-activate LSRO licensees did not meet the requirements of 10 CFR 55.53(f)(2).

The inspector used NRC Inspection Manual, Manual Chapter (MC) 0612, "Power Reactor Inspection Reports," Appendix B, and MC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)." The performance deficiency is not subject to traditional enforcement because it did not have actual safety consequences, there was no evidence of willfulness, and it does not impact the NRC's ability to perform its regulatory function. The performance deficiency is more than minor because it is similar to example 2h in Appendix E of MC 0612. MC 0609, Appendix I is entered because the performance deficiency is related to operator license conditions (MC0612, Appendix B, second section C, question # 9). The performance deficiency is an operator requalification issue related to operator license conditions (Appendix I flowchart block # 24, a "YES" response which leads to flowchart block #27). Since the inspection revealed more than 20% of the LSRO license reactivations to support refueling operations did not meet the requirements of 10 CFR 55.53(f)(2), the performance deficiency indicates a "Green Finding." Accordingly, the performance deficiency was determined to be of very low safety significance (Green).

Enforcement

10 CFR 55.53(f)(2), requires that for LSROs, who wish to reactivate their licenses, to complete at least one shift under-instruction under the direction of a senior operator and "in the position to which the individual will be assigned." Contrary to this requirement, between 1993 and 2002 the licensee re-activated their inactive senior operators limited

to fuel handling by allowing them to complete this refuel floor training on their own with no direct supervision from a senior operator. Because of the very low safety significance, and because the issue is in the licensee's corrective action program (ARs # A1295039 and A1378603), it is being treated as a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: **NCV 05000277/2003004-01 and 05000278/2003004-01, Did Not Meet 10 CFR 55.53(f)(2) When Reactivating Senior Operators to Support Fuel Handling**.

The licensee ceased their prior practices at the time of the 2002 inspection and have initiated a corrective action item to revise their Operator Requalification Program Manual to change their methods for re-certifying inactive SRO license holders to perform Fuel Handling Supervisor duties. This revision will require that "all parts of the reactivation will be performed with the accompaniment of an active SRO or LSRO." In addition, the licensee will initiate further revisions to their program consistent with the following NRR guidance provided as part of this resolution.
"*... the facility licensee can satisfy the intent of the regulation by implementing a reactivation program that specifies, in detail, the refueling tasks, activities, and procedures that an (L)SRO must satisfactorily complete or simulate (e.g., by using dummy fuel assemblies) in order to demonstrate watch-standing proficiency. Moreover, such a program shall exercise positive control to ensure that the required tasks, activities, and procedures are completed within a reasonable period of time (ideally, no more than one week) before the (L)SRO is assigned to supervise refueling shift functions*."

2. Routine Resident Licensed Operator Training Activities Review (71111.11Q)

a. Inspection Scope

On August 12, 2003, the inspectors observed one session of licensed operators' performance during crew simulator training for loss of secondary containment and ATWS for low vacuum. The inspectors observed and evaluated usage of Emergency Operating and Planning procedures by operations personnel. This observation included evaluating the critiques of the operators' performance to ensure that any operator performance errors were detected and corrected. The inspectors focused on the operating crew's satisfactory completion of critical tasks, including proper and timely identification and classification of emergencies. The inspectors also evaluated whether the operators adhered to Technical Specifications, emergency plan implementation and the use of emergency operating procedures. The inspectors discussed the training drill, simulator performance and critique with operators, shift supervision, operations management and training instructors. This inspection activity represented one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation (71111.12Q)

a. Inspection Scope

The inspectors reviewed the follow-up actions for issues identified on systems, structures, or components (SSCs) and the performance of these SSCs, to assess the effectiveness of Exelon's maintenance activities. The inspectors verified that problem identification and resolution of this one issue had been appropriately monitored, evaluated, and dispositioned in accordance with Exelon's procedures and the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance." In addition, the inspectors reviewed selected SSC classification, performance criteria and goals, and corrective actions to verify that the actions were reasonable and appropriate. This inspection activity represented one sample. The following equipment problem and documents were reviewed:

System

- Emergency cooling water pump discharge check valve (CHK-O-48-506) stuck open

Procedures and Documents

- Peach Bottom Health Overview Documents
- Peach Bottom Maintenance Rule Bases Documentation
- ER-AA-310, Revision 2, "Implementation of the Maintenance Rule"
- ER-AA-310-1002, Revision 1, "Maintenance Rule - SSC Risk Significance Determination"
- ER-AA-310-1003, Revision 2, "Maintenance Rule - Performance Criteria Selection"
- ER-AA-310-1004, Revision 1, "Maintenance Rule - Performance Monitoring"
- ER-AA-310-1005, Revision 1, "Maintenance Rule - Dispositioning between (a)(1) and (a)(2)"
- Action Request (A/R) # A1355640

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors reviewed Exelon's risk evaluations and contingency plans for selected planned and emergent work activities to verify that appropriate risk evaluations were performed and to assess Exelon's management of overall plant risk. The inspectors compared the risk assessments and risk management actions against the requirements of 10 CFR 50.65(a)(4) and the recommendations of NUMARC 93-01 Section 11, "Assessment of Risk Resulting from Performance of Maintenance Activities." The inspectors verified that risk assessments were performed when required and appropriate risk management actions were identified.

The inspectors attended planning meetings and discussed the risk management of the activities with operators, maintenance personnel, system engineers, and work coordinators to verify that risk management action thresholds were identified correctly. The inspectors also verified that appropriate implementation of risk management actions were performed. This inspection activity represented five samples. The following planned and emergent work activities were reviewed:

- Emergency service water planned maintenance
- Risk of 3 high pressure service water and reactor core isolation coolant outage
- Emergency cooling water outage window and 2 high pressure service water testing during E2 diesel generator outage
- Station blackout system with 2 high pressure coolant injection
- Troubleshooting Unit 2 group III spurious initiation (CR# 00169219)

In addition, the inspectors reviewed the assessed risk configurations against the actual plant conditions and any in-progress evolutions or external events to verify that the assessments were accurate, complete, and appropriate for the issues. The inspectors performed control room and field walkdowns to verify that compensatory measures identified by the risk assessments were appropriately performed.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions (71111.14)

a. Inspection Scope

The inspectors reviewed plant computer and recorder data, operator logs and approved procedures while evaluating the performance of operations, engineering, and instrument and control personnel in response to one non-routine evolution. The inspectors assessed personnel performance to determine whether the operator's response was appropriate and in accordance with procedures and training. The inspectors also assessed whether engineering and instrument and control personnel followed procedures, as required, and were properly trained and briefed prior to performing work evolutions. This inspection activity represented one sample. The following non-routine evolution was observed or reviewed:

- Unit 2 automatic reactor scram due to fan belt material in the isophase bus duct creating a generator high voltage neutral ground fault resulting in a generator lockout and main turbine trip

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed operability evaluations to assess the adequacy of the evaluations, the use and control of compensatory measures, compliance with the Technical Specifications, and the risk significance of the issues. The inspectors verified that the operability determinations were performed in accordance with LS-AA-105, Revision 0, "Operability Determinations" and CC-AA-11, Revision 0, "Nonconformances." The inspectors used the Technical Specifications, Technical Requirements Manuals, the UFSAR and associated Design Basis Documents as references during these reviews. This inspection activity represented five samples. The issues reviewed included:

- Drywell protection plates analysis (AR# A1339550)
- Unit 2 reactor manual control during replacement of control rod select switch
- E2, E3, E4, emergency diesel generators with swagelok compression fittings installed on the turbo chargers (ECR PB-03-00303)
- Unit 2 reactor core isolation coolant system during Unit 2 scram
- Main steam line high temp switch (CR #167356, AR# A1425994)

b. Findings

Finding 1 - Unit 2 Reactor Core Isolation Coolant System During Unit 2 Scram

Introduction

The inspectors identified a non-cited violation of very low safety significance (Green) of 10 CFR 50, Appendix B, Criterion XVI, because Exelon did not adequately correct a significant condition adverse to quality, identified during a December 21, 2002 scram, associated with the inoperability of the Unit 2 reactor core isolation cooling (RCIC) pump in the automatic flow control mode. As a result of not adequately correcting this significant condition adverse to quality, the Unit 2 RCIC pump was not able to deliver the Technical Specification required 600 gpm flow rate into the reactor vessel, at normal reactor pressure, while operating in the automatic flow control mode during a July 22, 2003 scram.

Description

During the scram on December 21, 2002, the RCIC pump had flow rate swings between approximately 200 gpm and 700 gpm, with a nominal flow rate of approximately 500 gpm, while the controller was operating in the automatic mode. The Technical Specification required flow rate from this pump is 600 gpm in automatic mode at normal reactor operating pressure. In NRC inspection report 05000277/2003007, a non-cited violation of Technical Specification 3.5.3 was identified for this inoperable condition that had existed since March 1994. Subsequent to that event, Exelon adjusted the gain setting on the flow controller. Exelon's post-maintenance testing did not verify the position of the RCIC turbine governor needle valve and did not include a RCIC system injection flow test into the reactor vessel.

During the scram on July 22, 2003, the RCIC pump had flow rate swings between approximately 400 gpm and 700 gpm, with a nominal flow rate of approximately 560 gpm, while the controller was operating in the automatic mode. The operators placed the controller in manual shortly after the flow swings were observed and continued to operate RCIC in manual to maintain reactor vessel level, until they lowered reactor pressure to allow the condensate system to assume level control. The RCIC pump performance on July 22, 2003, demonstrated that Exelon's corrective actions for the December 21, 2002, scram were not effective and did not prevent a repeat of the flow rate swings that continued to cause RCIC to be inoperable.

After the July 2003 scram, Exelon adjusted the flow controller gain, reset the RCIC turbine governor needle valve to within vendor specifications, and performed a RCIC system injection flow test into the reactor at rated pressure conditions. Exelon's extent of condition review included verification that the Unit 3 RCIC turbine governor needle valve setting was correct.

Analysis

Not adequately correcting a significant condition adverse to quality following the December 2002 scram associated with the operability of RCIC, as required by 10 CFR 50 Appendix B Criterion XVI is considered a performance deficiency. Subsequent to the July 2003 scram, additional gain-set adjustment and adequate post-maintenance testing were required to restore RCIC to an operable status. Traditional enforcement does not apply for this issue because it did not have any actual safety consequences or the potential for impacting the NRC's regulatory function and was not the result of any willful violations of NRC requirements.

This finding is considered more than minor because it is associated with the design control attribute of the Mitigating Systems Cornerstone and adversely affects the objective, in that, the capability of RCIC was degraded to respond to initiating events to prevent undesirable consequences. This finding is of very low safety significance (Green) using Phase 1 of the Significance Determination Process (SDP) for Reactor Inspection Findings for At-Power Situations. This issue is of very low safety significance because there was no loss of safety function for RCIC and the finding is not risk significant because of seismic, flood, fire or severe weather. Unit 2 RCIC pump flow was high enough (i.e., a nominal flow rate of approximately 560 gpm), in the automatic flow control mode, even with the swings in flow rate, to maintain reactor vessel water level. Additionally, the RCIC pump met the design basis flow with the RCIC flow controller in manual. Exelon entered this issue into their corrective action program as Condition Report (CR) #168861.

The contributing cause of this finding relates to the Problem Identification and Resolution cross-cutting area. Exelon did not take adequate corrective action after the self revealing problems on RCIC in the December 2002 reactor scram.

Enforcement

10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires that for significant conditions adverse to quality, corrective action be taken to preclude repetition. Contrary to these requirements, Exelon did not adequately correct a significant condition adverse to quality. Exelon did not adequately correct the RCIC pump flow oscillation identified on December 21, 2002 because the RCIC pump flow oscillation recurred on July 22, 2003. RCIC system remained inoperable in that period December 21, 2002 through July 22, 2003, since the RCIC pump could not meet the required flow (i.e., a minimum of 600 gpm) into the reactor vessel, at normal reactor pressure, with the flow controller in automatic. This violation of 10 CFR 50, Appendix B, Criterion XVI, is being treated as a non-cited violation consistent with Section VI.A.1 of the NRC Enforcement Policy: **NCV 05000277/2003004-02, Inadequate Corrective Actions on Unit 2 for Reactor Core Isolation Cooling Pump Automatic Flow Control**.

Finding 2 - Unit 2 Main Steam Line High Temperature Switch

Introduction:

The inspector identified an unresolved item related to 10 CFR 50, Appendix B, Criterion 16, because during the period of July 2001 through July 2003, Exelon did not adequately correct a condition adverse to quality, specifically a high Unit 2 steam tunnel temperature condition that was not representative of a steam leak. Consequently, on July 22, 2003, following a turbine trip and scram of Unit 2, a high main steam tunnel temperature condition, that was not representative of a steam leak, caused all main steam isolation valves to close resulting in a loss of the normal heat sink and reactor feed water system. This is an unresolved item (URI) pending completion of the Significance Determination Process (SDP).

Description:

During the July 22, 2003, Unit 2 scram main steam isolation valves (MSIVs) closed about 13 minutes after the reactor scram because the Unit 2 main steam tunnel temperature increased from about 161 °F to 192 °F, the setpoint for automatic closure of the MSIVs. High temperature in the main steam tunnel may be indicative of a steam leak in the steam tunnel which would warrant automatic closure of the MSIVs. The main steam tunnel temperature increase following the reactor scram on July 22, 2003, was not caused by a steam leak. The temperature increase was due to the expected Group 3 isolation that caused isolation of normal reactor building ventilation and the automatic start of the "B" train of the standby gas treatment system. The closure of the MSIVs resulted in a loss of the main condenser and reactor feedwater system, thereby complicating operator response to the scram.

Exelon had information since July 2001, indicating that, after a Group 3 isolation, the main steam tunnel temperature rapidly increases to levels that are at or near the levels that would activate the primary containment isolation logic that would cause the MSIVs to close. Action Request (AR) 1325657, dated July 1, 2001, documented a high main steam line tunnel temperature condition on Unit 2 following a scram and subsequent Group 3 isolation. Although the main steam tunnel temperature on this occasion did not reach the trip condition on all temperature channels and cause an MSIV closure, the peak temperature reached the trip set point on one channel. Condition Report (CR) 154878, dated April 20, 2003, documented an unexpectedly high main steam tunnel temperature condition following a Group 3 isolation while performing planned maintenance on Unit 2. Main steam tunnel temperature peaked within three degrees of the MSIV closure value.

Exelon did not adequately address the high steam tunnel temperature conditions in the July 2001 and April 2003 events, in order to preclude a high temperature condition, that was not due to a valid steam leak, from causing closure of the MSIVs on July 22, 2003. Following the July 2001 event, Exelon determined that the plant's response was not abnormal. Following the April 2003 event, Exelon found a supply damper not fully open and opened the damper. Following both events Exelon took no specific action to reduce the probability that a high steam tunnel temperature, that was not due to a valid steam leak condition, would cause a MSIV closure condition.

The main steam line tunnel exhaust temperature on Unit 2 is approximately 45°F higher than the main steam line tunnel exhaust temperature on Unit 3. Exelon has identified that the cause of the higher main steam line tunnel exhaust temperatures to be a difference in the location of the temperature probes on Unit 2 versus Unit 3. Although the probes for both units are located in the exhaust duct, in the vicinity of the mixture of reactor building and MSIV outboard exhaust ventilation, the arrangement of the probes relative to the mixing ventilation flows is different for the two units. Unit 2 indicates approximately 45°F closer to the high temperature trip set point than Unit 3, resulting in less time for Unit 2 operators to take action following a Group 3 isolation, in order to prevent MSIV closure in the absence of an actual steam leak.

Subsequent to this event, Exelon used the site specific simulator to evaluate response time of the main steam tunnel temperature increase and the adequacy of operator procedure guidance to control the temperature rise after a reactor scram. The operator response to the simulated reactor scram resulted in the restoration of normal ventilation to the main steam tunnel in a time exceeding 23 minutes. The restoration time was significantly greater than the MSIV high air temperature isolation time of 13 minutes after the scram event on July 22, 2003, and would not have prevented the MSIV isolation.

Analysis:

The performance deficiency in this case is that Exelon did not correct a condition adverse to quality, specifically a high temperature condition that was not representative of a steam leak caused a MSIV closure, as required by 10 CFR 50 Appendix B, Criterion XVI. Traditional enforcement does not apply because the issue did not result in any actual safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements or Exelon's procedures. The finding is considered greater than minor in that the issue is associated with the equipment performance attribute of the mitigating systems cornerstone and adversely affects the mitigating systems cornerstone objective to assure availability of systems that respond to initiating events to prevent undesirable consequences. MSIV closure on a high main steam tunnel temperature that was not representative of a steam leak had the undesirable consequence of removing the normal source of feed water and the normal heat sink from the reactor and complicated the operator actions required to place the reactor in a safe shutdown condition. The finding is also associated with the equipment performance attribute of the Initiating Events cornerstone and adversely affects the objective of limiting the likelihood of those events that upset plant stability. A high steam tunnel temperature condition that is not representative of a steam leak due to a Group 3 isolation would remove the normal source of feed water and heat sink and cause a reactor scram.

A SDP for Inspector Findings for At Power Conditions phase 1 screening of the finding screened to phase 2 because the finding affects both the Initiating Events and Mitigating

Systems Cornerstones. The phase 2 screening directed that a phase 3 screening be accomplished. Exelon's not preventing the high temperature trip of MSIV's following a reactor scram on July 22, 2003, is an unresolved item pending the results of the phase 3 SDP for At-Power Situations. Exelon entered the finding into its corrective action program as CR 168859.

This finding is specifically related to the cross-cutting area of Problem Identification and Resolution. Although Exelon documented high main steam tunnel temperatures in their corrective action program on July 1, 2001, and again on April 20, 2003, Exelon did not correct the high main steam line tunnel temperature condition that was not representative of a steam leak on Unit 2 to prevent the closure of the MSIVs on Unit 2 MSIVs on July 22, 2003.

Enforcement:

10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires licensees to correct conditions adverse to quality. Contrary to the above, between July 1, 2001, and July 22, 2003, Exelon did not correct the known high main steam tunnel temperature condition that was not representative of a steam leak. Consequently, on July 22, 2003, the high main steam tunnel temperature condition caused a MSIV closure following a scram, complicating the operator actions required to place the reactor in a safe shutdown condition. Pending determination of the finding's safety significance, this finding is identified as an unresolved item (URI): **URI 05000277/2003004-03, Inadequate Corrective Actions for High Unit 2 Steam Tunnel Temperature**.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors observed portions of post-maintenance testing activities in the field and reviewed selected test data at the job site. The inspectors observed whether the tests were performed in accordance with the approved procedures and assessed the adequacy of the test methodology based on the scope of maintenance work performed. In addition, the inspectors assessed the test acceptance criteria to verify whether the test demonstrated that the tested components satisfied the applicable design and licensing bases and the TS requirements. The inspectors reviewed the recorded test data to evaluate whether the acceptance criteria were satisfied. This inspection activity represented five samples. The specific activities reviewed included:

- RT-O-052-202-4, "E4 Diesel Generator Load Run," following exhaust gasket repair
- ST-O-010-301-3, "'A' RHR Loop Pump, Valve, Flow, and Unit Cooler Functional and Inservice Test," following heat exchanger maintenance
- ST-O-013-301-3, "RCIC Pump Valve and Flow," following Reactor Core Isolation Coolant mini outage

- SP-AO-2143-2 Test, “Reactor Core Isolation Coolant Flow Control and Turbine Governor Stability Injection After Controller and Governor Tuning to Fix Oscillations”
- ST-I-07G-103-2, “Primary Containment Isolation System (PCIS) Group 3 Logic System Functional Test,” following K24 relay replacement

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the Unit 3 refueling outage, which started on September 15, 2003, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the refueling outage, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below. This inspection activity represented one sample. Documents reviewed during the inspection are listed in the Attachment.

- New fuel receipt inspection
- Review outage plan
- Verify cooldown and cooldown controls
- Track operability of emergency core cooling system
- Verify licensee’s risk control plan
- Track reactor vessel level instrumentation availability

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed and observed portions of surveillance tests, and compared test data with established acceptance criteria to verify the systems demonstrated the capability of performing the intended safety functions. The inspectors also verified that the systems and components maintained operational readiness, met applicable technical specification requirements, and were capable of performing the design basis functions. This inspection activity represented four samples. The observed or reviewed surveillance tests included:

- ST-O-09A-325-2, Revision 3, “Standby Gas Treatment Subsystem Operability Test”
- ST-O-013-200-2, Revision 14, “Reactor Core Isolation Cooling (RCIC) Flow Rate at ≤ 175 psig”
- ST-O-052-702-2, Revision 12, “E2 Emergency Diesel Generator 24-hour Endurance Test”
- RT-O-032-300-3, Revision 12, “Unit 3 High Pressure Service Water (HPSW) Pump, Valve and Flow”

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed a temporary plant modification (ECR 01-01153, Revision 0) associated with an Unit 3 residual heat removal (RHR) testable check valve (AO-3-10-46A). The objectives of this review were to verify that (1) the design bases, licensing bases, and performance capability of risk significant structures, systems, and components had not been degraded through this modification, and (2) that implementation of the modification did not place the plant in an unsafe condition. The inspectors verified the modified equipment alignment through control room instrumentation observations; UFSAR, drawing, procedure, and work order reviews; and plant walkdowns of accessible equipment (see Supplementary Information for a complete listing of documents reviewed). This inspection activity represented one sample.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

1EP2 Alert and Notification System Testing (71114.02)

a. Inspection Scope

The inspectors conducted an onsite review of Exelon’s alert and notification system (ANS) to ensure prompt notification of the public to take protective actions. The inspector reviewed: (1) EP-MA-121-1002, “ANS Description Testing Maintenance and Performance Trending Program”; (2) 2002/2003 siren activation/test records; and (3) 2002/2003 siren maintenance records. The inspector interviewed the siren program coordinator and reviewed condition reports associated with siren failures to determine if failures were being immediately assessed and repaired. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 02, and the applicable planning standard, 10 CFR 50.47(b)(5) and its related 10 CFR 50, Appendix E requirements were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation Testing (71114.03)

a. Inspection Scope

An onsite review of the licensee's ERO augmentation staffing requirements and the process for notifying the ERO was conducted to ensure the readiness of key staff for responding to an event and timely facility activation. The inspector reviewed Exelon's emergency plan qualification records for key ERO positions, 2002/2003 communication pager test records and associated condition reports. In addition, the inspector reviewed Procedures TQ-AA-113, "ERO Training and Qualification" and TQ-EP-AA-1102, "ERO Fundamentals." The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 03, and the applicable planning standard, 10 CFR 50.47(b)(2) and its related 10 CFR 50, Appendix E requirements were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level (EAL) Revision Review (71114.04)

a. Inspection Scope

A regional in-office review of revisions to the emergency plan, implementing procedures and EAL changes was performed to determine that changes had not decreased the effectiveness of the plan. The revisions covered the period from September 2002 through June 2003. Onsite, the inspector reviewed the 10 CFR 50.54(q) reviews associated with the implementation of a new Standard Emergency Plan and the Limerick Annex Emergency Plan. In addition, the associated Plant Operations Review Committee (PORC) meeting minutes were reviewed to determine the adequacy of the review and approval process. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 04, and the applicable requirements in 10 CFR 50.54(q) were used as reference criteria.

b. Findings

Introduction

The inspector identified a Severity Level IV Non-Cited Violation of 10 CFR 50.54(q). During the implementation of a new Standard Emergency Plan, Exelon did not retain a record that determined whether a Decrease-in-Effectiveness (DIE) had or had not occurred when Exelon generated the new Standard Emergency Plan that deleted portions of the previous Combined Limerick/Peach Bottom Emergency Plan.

Description

In August 2002, Exelon generated a new Standard Emergency Plan for use by their power stations located in the mid-west, Limerick, Peach Bottom and Three Mile Island. Exelon developed annex plans that contained information specific to each station. The inspector reviewed the associated 10 CFR 50.54(q) DIE reviews and determined that Exelon had no documentation to determine whether a DIE had or had not occurred when Exelon generated the new Standard Emergency Plan that deleted portions of the previous Combined Limerick/Peach Bottom Emergency Plan.

Analysis

The performance deficiency is that Exelon did not retain the required record for changes made in the Combined Limerick/Peach Bottom Emergency Plan. Due to the nature of this issue (affecting the regulatory process), traditional enforcement is used in lieu of the Significance Determination Process (SDP).

Enforcement

10 CFR 50.54(q) states in part that the licensee may make changes to the emergency plans without Commission approval only if the changes do not decrease the effectiveness of the plans and the licensee shall retain a record of each change for a period of three years from the date of the change. Contrary to the above, Exelon did not retain a record of its determination whether a DIE had or had not occurred when it generated a new Standard Emergency Plan that deleted portions of the previous Combined Limerick/Peach Bottom Emergency Plan.

Changing emergency plan commitments without documentation impacts the NRC's ability to perform its regulatory function and is therefore processed through traditional enforcement as specified in Section IV.A.3 of the Enforcement Policy, issued May 1, 2000 (65 FR 25388). According to Supplement VIII of the Enforcement Policy, this finding was determined to be a Severity Level IV because it involved a failure to meet a requirement not directly related to assessment and notification. Because the licensee has entered this issue into its corrective action program (CR No. 172088), this finding is being treated as non-cited violation (Severity Level IV) consistent with Section VI.A of the NRC Enforcement Policy: **NCV 05000277/2003004-04 and 05000278/2003004-04, Inadequate Emergency Plan Change Documentation, 10 CFR 50.54(q)**.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspector reviewed corrective actions identified by Exelon pertaining to findings from drill/exercise reports for 2002 and 2003 and the associated conditions reports to determine the significance of the issues and to determine if repeat problems were occurring. Reviewed condition reports and corrective action program procedures are contained in an attachment to this report. In addition, the inspector reviewed the following Nuclear Oversight (NOS) audit reports: (1) 2002 Fourth Quarter Continuous Assessment Report; (2) 2003 First and Second Quarter Continuous Assessment Reports; and (3) EP 50.54(t) Audit Report dated July 2, 2003. In addition, the inspector reviewed memorandum dated February 21, 2003 from NOS concerning EP Performance Issues and Memorandum dated July 17, 2003 issuing a First Level of Escalation Notice regarding continual EP performance issues. These documents were reviewed to assess Exelon's ability to identify issues, assess repetitive issues, and the effectiveness of corrective actions through their independent audit process. Also, two common cause reports generated in 2002 and 2003 discussing EP performance issues not being adequately addressed were reviewed. This inspection was conducted according to NRC Inspection Procedure 71114, Attachment 05, and the applicable planning standard, 10 CFR 50.47(b)(14) and its related 10 CFR 50, Appendix E requirements were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed a drill on August 19, 2003, that simulated tornado damage inside the protected area. The inspectors focused on the performance of risk significant evolutions these individuals in a simulated main control room. These risk significant drills tested these individuals adherence to Technical Specifications, satisfactory completion of critical tasks, and timely identification and emergency classification. The inspectors evaluated the individuals recognition of abnormal conditions and proper emergency classification. The inspectors discussed the training, simulator scenarios and critiques with training instructors, shift supervision, and operations management. The inspectors observed the licensee's critique of personnel performance and verified that any weaknesses or deficiencies observed during these drills were discussed and evaluated. This inspection activity represented one sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety [OS]

2OS1 Access Controls to Radiologically Significant Areas (71121.01)

a. Inspection Scope

The inspector reviewed selected activities and associated documentation in the below listed areas. The evaluation of Exelon's performance in these areas was against criteria contained in 10 CFR 20, applicable Technical Specifications, and applicable Exelon procedures.

Plant Walkdowns, Job-In-Progress Reviews

The inspector toured selected station radiological controlled areas and reviewed housekeeping and material conditions, posting, barricading, and access controls to radiological areas. During station tours, the inspector reviewed ongoing work activities associated with the 3A residual heat removal (RHR) system heat exchanger and inspection and loading of new fuel into the Unit 3 fuel storage pool. The reviews included evaluation of the adequacy of applied radiological controls, including radiation work permit adherence, radiological surveys, job coverage, and contamination controls.

The inspector reviewed and discussed internal dose assessments for 2002 and 2003, since the previous inspection, to identify any actual occupational internal doses greater than 50 millirem committed effective dose equivalent (CEDE). The review also included an evaluation of the adequacy of associated dose assessments, as appropriate. In addition, the review included an evaluation of Exelon's program for evaluation of potential intakes associated with transuranic radionuclides.

High Risk Significant, High Dose Rate HRA and VHRA Controls

The inspector discussed procedure changes for high radiation area access controls since the last inspection to determine if the changes resulted in a reduction in the effectiveness and level of worker protection.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspector conducted the following activities to determine if Exelon was properly implementing operational, engineering, and administrative controls to maintain personnel exposure as low as is reasonably achievable (ALARA). Implementation of these controls was reviewed against the criteria contained in 10 CFR 20, applicable industry standards, and applicable station procedures.

Inspection Planning

The inspector reviewed pertinent information regarding plant collective exposure history, current exposure trends, and ongoing or planned activities in order to assess current performance and exposure challenges. The inspector determined the plant's current 3-year rolling average collective exposure.

The inspector determined the site specific trends in collective exposures (using NUREG-0713 and plant historical data) and source-term (average contact dose rate with reactor coolant piping) measurements.

The inspector reviewed planning and preparation for the upcoming Unit 3 maintenance outage. The inspector selected seven work activities likely to result in the highest personnel collective exposures and reviewed the planning and preparation for those work activities. The work activities reviewed were control rod drive change-out, in-service inspection, recirculation pump impeller and motor replacement, scaffolding activities, temporary shielding, main steam isolation valve work, and radiological controls coverage. The inspector also selectively reviewed implementation of action items from previous post-job reviews for these work activities, as applicable. The inspector also reviewed exposures of individuals from selected work groups to evaluate significant exposure variations which may exist among workers.

Source-Term Reduction and Control

The inspector reviewed plans to determine if Exelon had developed contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry.

The inspector reviewed and discussed the Exelon's understanding of the plant source-term, including knowledge of input mechanisms to reduce the source term; and the source-term control strategy in place. The inspector reviewed and discussed Exelon's cobalt reduction strategy and shutdown ramping and operating chemistry plans designed to minimize the source-term external to the core.

The inspector attended the August 13, 2003, Station ALARA Council Meeting (Meeting 03-03). The inspector observed ongoing discussions regarding dose reduction/planning activities.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03)

a. Inspection Scope

The inspector reviewed audits and self-assessments to determine if identified problems were entered into the corrective action program for resolution. The inspector reviewed condition reports and Action Requests to evaluate Exelon's threshold for identifying, evaluating, and resolving problems relating to radiation safety instrumentation. (See Section 4OA2)

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors reviewed selected records at the station to assess the accuracy and completeness of the NRC Performance Indicator (PI) data. The records reviewed included Technical Specification limiting condition for operation logs, system surveillance tests, licensee event reports, action requests and condition reports. The information reviewed was compared against the criteria contained in Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment PI Guideline, Revision 2. The inspectors verified that conditions met the NEI criteria, were recognized, identified, and accurately reported. This inspection activity represented three samples. The following specific indicators were reviewed:

- Units 2 and 3 safety system functional failures
- Occupational exposure control effectiveness

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

1. Routine Problem Identification and Resolution

a. Inspection Scope

The inspector selectively reviewed self-assessments and audits to determine if identified problems were entered into the corrective action program for resolution. The inspector evaluated the database for repetitive deficiencies or significant individual deficiencies to identify if Exelon's self-assessment activities were identifying and addressing these deficiencies. The review also included evaluation of data to determine if any problems involved PI events with dose rates greater that 25 R/hr at 30 centimeters, greater than 500 R/hr at 1 meter or unintended exposures greater than 100 mrem total effective dose equivalent (TEDE), 5 rem shallow dose equivalent (SDE), or 1.5 rem lens dose equivalent (LDE).

The review also included a review of problem reports since the last inspection which involved potential radiation worker or radiation protection personnel errors to determine if there was an observable pattern traceable to a similar cause. The review included an evaluation of corrective actions, as appropriate.

The inspector reviewed audits and self-assessments to determine if identified problems were entered into the corrective action program for resolution. The inspector also reviewed twenty Action Requests to evaluate Exelon's threshold for identifying, evaluating, and resolving problems relating to occupational radiation safety. The review included a check of possible repetitive issues such as radiation worker or radiation protection technician errors. The following documents were reviewed:

- Site Integrated Performance Assessment Report, Second Quarter 2003
- Radiological protection Site Integrated Performance Assessment, First Quarter 2003, Second Quarter 2002
- Nuclear Oversight Corporate Comparative Audit Report, 2003 Health Physics/Radiation Protection Audit
- Focus Area Self-Assessment Reports: Radiation Protection, 2003; External and Internal Dosimetry 2002, 2003; Respiratory Protection 2003, Internal Dosimetry 2001; Radiation Protection Management Leadership 2003; Radiation Protection Instrumentation 2002
- Assignment Reports (ARs): 165767, 134162, 132305,1600157, 160215, 132692, 150454, 160106, 160145, 163836, 148870, 158578, 141861, 132305, 136792, 145050, 136782
- Condition Reports (CRs): 153912, 124961
- Nuclear Oversight Continuous Oversight Report, First and Second Quarter 2003
- Procedure Adherence/Human Performance Error Prevention Improvements Plan

This review was against the criteria contained in 10 CFR 20, Technical Specifications, and the station procedures.

The inspector reviewed Exelon's self-assessments and audits related to the ALARA program since the last inspection to determine if the licensee's overall audit program's scope and frequency (for all applicable areas under the Occupational Cornerstone) meet the requirements of 10 CFR 20.1101(c).

b. Findings

No findings of significance were identified.

2. Annual Sample Review - Unit 3 HPCI Turbine Speed Limiter Calibration

a. Inspection Scope

The inspector performed a Problem Identification and Resolution Inspection for one selected issue to evaluate the effectiveness of Exelon's corrective actions for this particular issue. Based on system risk significance, the inspector selected condition report (CR) 112681 associated with the high pressure coolant injection (HPCI) system for this review. During a Safety System Design Inspection in June 2002, an NRC inspector questioned the Unit 3 HPCI turbine speed limit. Engineering determined that the Unit 3 HPCI high speed limiter was not properly calibrated and initiated CR 112681 to investigate the cause and effect corrective actions. Engineering determined that the margin to the HPCI overspeed trip was reduced, however, HPCI remained operable and capable of performing its safety function.

The inspector reviewed the apparent cause evaluation report, the associated corrective action assignments, related corrective maintenance documents, surveillance test results, and the HPCI system health report (see Supplementary Information, Section C, for a complete listing of documents reviewed). The inspector also conducted several control room instrumentation and in-plant system walkdowns, including a detailed walkdown with the HPCI system engineer, to assess the operational readiness, configuration control, and material condition of the Unit 2 & 3 HPCI systems.

b. Findings and Observations

No findings of significance were identified.

Based on HPCI system walkdowns and surveillance test (ST) reviews, the inspector observed that plant personnel generally identified HPCI system issues and equipment deficiencies at an appropriate level. Nevertheless, the inspector identified that equipment operators had recorded three HPCI oil temperature monitoring points outside of their respective nominal ranges and did not document comments or initiate follow-up action during a Unit 2 HPCI ST in April 2003. The inspector noted that the procedure did not require additional operator action for these parameters, however, operators had initiated action requests for similar conditions found during other HPCI STs in accordance with management expectations. The HPCI engineer stated that he planned to provide additional procedure guidance for the operators relative to these trending data points.

Engineering's apparent cause evaluation (ACE) appropriately addressed causal factors, work practices, training, extent of condition, and previous occurrences. Engineering identified two causal factors for the HPCI speed limiter setpoint deficiency and identified actions to address these issues. The inspector noted that engineering's identified action to address the first causal factor did not clearly address the apparent cause. In particular, the first causal factor involved an incorrectly measured HPCI turbine governor null voltage. Engineering noted that procedure guidance (RT-X-023-210-3) was adequate but could be enhanced. Exelon initiated assignment No. 3 to enhance the associated procedures for both units. However, engineering did not identify any corrective actions for this causal factor (Exelon's corrective action program clearly distinguishes between enhancements and corrective actions). For example, although the ACE evaluator identified through interviews with I & C technicians that they had made erroneous assumptions regarding meter polarity that directly contributed to the miscalibration, engineering did not target any corrective action toward improving I & C technician training relative to proper polarity checks in order to preclude recurrence.

Exelon's classification and prioritization of the assigned corrective actions and enhancements were commensurate with the safety significance. Exelon completed assigned corrective actions in a timely manner. The procedure enhancements remain in the approval stage and are tracked within the plant information management system (A0878336-05, A0878337-04, A1410834-01, A1410834-01).

3. Cross-References to PI&R Findings Documented Elsewhere

Section 1R15 describes a finding for failure to adequately correct a significant condition adverse to quality, identified during a December 21, 2002, scram associated with the inoperability of the Unit 2 reactor core isolation cooling (RCIC) pump in the automatic flow control mode.

Section 1R15 describes a finding for failure to adequately correct a condition adverse to quality, specifically a high Unit 2 steam tunnel temperature that was not representative of a steam leak.

4OA3 Event Followup (71153)

1. (Closed) LER 05000278/2003001-00, Loss of Capability of the Unit 3 10CFR 50 Appendix R Alternate Control Station

   On May 14, 2003, station instrument and control technicians discovered during surveillance testing, that a pressure indicator on the Unit 3 HPCI alternate control station did not respond to a test signal. Further investigation revealed that a wire for the station power supply was broken during maintenance activities and the power supply was de-energize for approximately nine days. The broken wire resulted in a loss of power to various reactor vessel and emergency core cooling system instrumentation at the station, such as reactor pressure and level, as well as loss of power to the HPCI turbine emergency speed control. Thus, this failure caused a loss of function for HPCI during scenarios that required evacuation of the control room and use of the alternate control station. In addition, this condition would have prevented operators from using the alternate control station to monitor some key reactor parameters.

   The inspectors performed an on-site inspection of this issue and documented the results in NRC Inspection Report 50-277/03-04, 50-278/03-04. The inspectors reviewed this LER and did not identify any new issues from this event. This LER is closed.

2. (Closed) LER 05000277/2003002-00, Condition Prohibited by TSs due to Inoperability of Standby Gas Treatment Filter Train

   On May 28, 2003, licensed operators were notified that approximately 4 inches of water (~170 gallons) was discovered in the bottom of the 'A' Standby Gas Treatment (SBGT) filter plenum during the performance of an annual surveillance. Further evaluation determined that a condition prohibited by Technical Specifications existed since this water intrusion resulted in the 'A' SBGT subsystem being inoperable between the worst-case time period of 11/21/02 until 12/18/02. The water in the 'A' SBGT filter plenum was promptly removed subsequent to discovery and appropriate filters were replaced. The 'A' SBGT subsystem was restored to an operable status by approximately 2200 hours on 5/29/03. There were no actual safety consequences as a result of this condition. This LER is closed.

3. (Closed) LER 05000277/2003003-00, Generator Bus Ground Caused by Foreign Material Results in Automatic Scram

   On July 22, 2003, Unit 2 automatically scrammed as a result of a fast closure of the main turbine control valves. This was a result of a main generator lockout due to a generator neutral high voltage ground fault from foreign material in the isophase bus duct contacting a bus conductor. Control rods fully inserted and Group 2 and 3 primary containment isolations occurred as expected. The Group 2 and 3 isolations resulted in loss of the normal ventilation in the steam tunnel that caused increasing temperature in the steam tunnel. The main steam isolation valves closed in response to the increasing temperature in the steam tunnel. The closure of the main steam isolation valves resulted in a loss of normal feedwater and second reactor scram signal was generated because of low reactor water level. The high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems were used to restore and control reactor water level. Exelon observed RCIC to have oscillating flow rates. Exelon subsequently determined that the oscillating flow rate was a Technical Specification inoperable condition for RCIC. A third reactor scram signal was generated in the transition of reactor water level control from HPCI to the normal feedwater system. The low reactor water level condition was restored to the normal band using the condensate system.

Section 1R14 reviewed operator actions. Section 1R15.1 identified a NCV for the inoperability of RCIC. Section 1R15.2 identified a NCV regarding not correcting a condition adverse to quality that resulted in a closure of the MSIVs. This event was entered into Exelon's corrective action program as AR #00168689. This LER is closed.

4O5A Other Activities

(Closed) URI 05000278/2003003-03: Unit 3 HPCI Alternate Control Station Loss of Power

Introduction

A Green NCV was identified for violation of Condition 2.C.4 of the operating license for Unit 3, related to the Unit 3 HPCI alternate control station being inoperable for safe shutdown of Unit 3 during specific scenarios.

Description

On May 13, 2003, during a surveillance test on the Unit 3 HPCI alternate control station, I&C technicians observed that a pressure indicator on the panel did not respond to a test signal. Further investigation revealed that a wire for the station power supply, E/S-9344A, was broken.

The broken wire resulted in a loss of power to the HPCI turbine emergency speed controller and to multiple reactor vessel and emergency core cooling system instrumentation at the control station, such as reactor pressure and level. Thus, this failure caused a loss of function for HPCI during scenarios that required evacuation of the control room and use of the alternate control station. In addition, this condition would have prevented operators from using the alternate control station to monitor some key reactor parameters such as reactor pressure and level.

Exelon's investigation determined that on May 5, 2003, I&C technicians did not complete the post-maintenance test, as specified in the work order, following maintenance activities on the control station that included calibration of an inverter associated with the power supply. During these activities, a technician moved the power supply, apparently causing the wire to break. The post-maintenance test would have detected the broken wire if it had been properly performed.

Exelon discovered the condition on May 13, 2003, when I&C technicians observed an unexpected response while performing surveillance test, SI3F-10-177-XXC2, Revision 1, “Calibration Check of Alternate Shutdown Panel RHR Heat Exchanger HPSW Flow Instruments FT/FI 3-10-177.” This test was not directly associated with the deenergized power supply. Since the identification of the failure mechanism was not within the intended scope of this test, this finding is considered self-revealing. The significance of the finding had not been determined at the conclusion of the last resident inspection period.

Analysis

The technicians did not complete the specified post-maintenance testing for work on the Unit 3 HPCI alternate control station power supply. This is a performance deficiency because the technicians did not follow Exelon’s instruction in the preventive maintenance work order. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function and was not the result of any willful violations of NRC requirements.

This finding is more than minor because it is associated with the human performance attribute of the Mitigating Systems cornerstone and adversely affects the cornerstone objective. The cornerstone objective is affected because for approximately nine days the HPCI alternative control station was unavailable. The HPCI Alternate Safe Shutdown Panel (HPCI ASP) allows the operators to control: the HPCI system for reactor coolant system (RCS) inventory control, two automatic depressurization system valves for RCS pressure control and depressurization (DEP) and the residual heat removal (RHR) system in the low pressure injection (LPI), for RCS inventory, and in the secondary modes including suppression pool cooling for containment heat removal (CHR) and shutdown cooling modes.

The finding was determined to be of very low safety significance (Green), based on a Phase 3 SDP analysis that evaluated the change in the core damage frequency (delta-CDF) and a large early release frequency (delta -LERF). The issue screened from the Phase 1 to the Phase 3 SDP because it involved the external event of a fire in the control room or cable spreading room leading to control room evacuation or equipment damage, that necessitates the use of the HPCI ASP. The Phase 3 analysis, conducted by a Region I Senior Reactor Analyst, used six scenarios and a method similar to the that used in NUREG/CR-4550 Vol. 4, Rev. 1, Part 3 Analysis of Core Damage Frequency : Peach Bottom, Unit 2 External Events. NUREG 4550 discussed the potential core damage relative to the need to use the HPCI ASP following a fire in the control room (section 5.10.1) and the cable spreading room (section 5.10.2) and was the current basis of the licensee’s Individual Plant Examination of External Events (IPEEE).

Some of the assumptions made in the analysis were:

- Power was unknowingly not supplied to the HPCI ASP for a period of nine days.
- The HPCI system speed controller lost power, making the HPCI system non-functional.

- The instrumentation necessary to monitor plant parameters while operating the two ADS valves and the RHR system lost power, essentially making DEP, LPI, and CHR non-functional.
- A control room fire which led to an evacuation or a cable spread room fire that was not suppressed and caused damage to normal control room control functions, would require the use of the HPCI ASP to support the HPI, CHR, DEP and LPI safety functions.
- RCIC operation was not directly affected by the loss of power to the HPCI ASP. However, the analysis assumed that RCIC may be affected, based on the location of instrument and control equipment in the control room and cable spread room.
- A 90% recovery credit was applied to restoration of suppression pool cooling in the long term for two scenarios where RCIC succeeded in supplying cooling water to the reactor vessel. This credit was assumed because the licensee's Technical Support Center would be manned to give direction on the operation of the RHR system locally and on the relative ease of identifying and fixing the damaged HPCI ASP power supply lead.
- A conditional containment failure probability of 0.5 was used for high pressure reactor vessel melt though LERF scenarios. This was based on information on direct containment heating provided in a recent NRC study (The Probability of High Pressure Melt Ejection Direct Containment Heating Failure of BWRs with Mark I Designs, ERI/NRC 03-204, August 2003). This appeared consistent with the results of NUREG-1150, Vol 1, Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants for the Peach Bottom Containment (Section 4.3), which indicated that the conditional probability of early drywell failure, given core damage, would be about 0.52 to 0.6 for internal and fire initiators, respectively.

In accordance with MC 609A and MC609H the six fire scenarios were evaluated relative to the delta-CDF and delta-LERF over the nine day period resulted in a very low safety significance determination. The dominate scenario for both delta-CDF and delta-LERF was a fire on the Unit 3 side of the cable spread room, that was not extinguished manually or by the manual operation of the cable spread room carbon dioxide fire suppression system, resulting in damage that cased the loss of RCIC and the inability to use failed Unit 3 HPCI ASP to control the plant shutdown.

A contributing cause of the Inoperable HPCI alternative control station was related to the Human Performance cross-cutting area. Specifically, I&C technicians did not follow procedures to perform the post-maintenance test specified in a maintenance work order. As a result, the control station was returned to service while in a degraded condition and was unavailable for operation of HPCI and monitoring of important reactor parameters for safe shutdown of Unit 3 in certain fire scenarios.

<u>Enforcement</u>

Condition 2.C.4 of the operating license for Unit 3 requires Exelon to implement and maintain the fire protection program described in the NRC Safety Evaluation Reports. Section 5.2, Method D and 5.3 of the Peach Bottom Fire Protection Plan (FPP) requires

that "alternate shutdown capability be available in case of a fire in the control room, the cable spreading room, the computer room or the emergency shutdown panel area." Contrary to the above, from May 5, 2003 until May 14, 2003, the Unit 3 HPCI alternate control station power supply was deenergized resulting in the loss of alternate shutdown capability for safe shutdown of the unit. Because the loss of ability to use the HPCI alternate control station during a fire in the control room envelope is of very low safety significance, and Exelon entered this issue into their corrective action program (CR #158665), this violation is being treated as an NCV, consistent with Section VI.A of the NRC enforcement policy: **NCV 0500278/2003004-05, Deenergized Unit 3 HPCI Alternate Control Station Power Supply**.

4OA6 Meetings, Including Exit

On October 16, 2003, the resident inspectors presented the inspection results to Mr. Rusty West and members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee-Identified Violations

The following findings of very low safety significance (Green) were identified by Exelon and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as non-cited violations (NCVs).

- 10 CFR 50.54(q), follow and maintain in effect emergency plan. Exelon did not properly inventory or maintain emergency response equipment kits located at local hospitals. This issue was discovered during an NOS audit. (CR No. 00163144).

- 10 CFR 50.54(q), follow and maintain in effect emergency plan. Exelon did not make available public education brochures for emergency response actions to operators of recreational areas in the 10 Mile EPZ. This issue was discovered during an NOS audit (CR No. 00163029).

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

R. West, Site Vice President
J. Mallon, Director, Training
J. Stone, Plant Manager
E. Eilola, Operations Director
C. Fritz, LSRO Program Coordinator
C. Goff, Exam Development/Operations Instructor
P. Davison, Maintenance Director
G. Stathes, Site Engineering Director
M. Anthony, Work Management Director
C. Behrend, Senior Manager Plant Engineering
B. Norris, Radiation Protection Manager
E. Anderson, Manager, Regulatory Assurance
W. Trump, Nuclear Security Manager
A. Coppa, Emergency Preparedness Manager
K. Langdon, Site Nuclear Oversight Manager
R. Lubaszewski, Rad Material Shipping Coordinator
G. McCarty, Radiological Engineering Manager
S. Wilson, Instrumentation Coordinator
S. Kobus, Radiation Protection Supervisor
T. Lee, Engineering
T. Martin, Manager, Support Health Physics
C. Crabtree, Radiation Protection Supervisor
D. Barron, Rad Engineer
J. Schwarz, Rad Engineer
H. McCrory, Dosimetry Physicist
J. Volz, Physicist
W. Scott, Chemist
H. McCory, Radiological Engineer
N. Weissenreider, Respiratory Physicist
C. Jordan, Chemistry Manager
J. Zardus, HPCI System Engineer
C. Arnone, EP Director
J. Karkoska, MAROG Emergency Preparedness Manager
J. Anderson, Program Coordinator
R. Rogers, Training Coordinator
J. Cohen, NOS auditor

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Closed

05000278/2003001-00	LER	Loss of Capability of the Unit 3 10CFR 50 Appendix R Alternate Control Station (Section 4OA3.1)
05000277/2003002-00	LER	Condition Prohibited by Technical Specifications due to Inoperability of Standby Gas Treatment Filter Train (Section 4OA3.2)
05000277/2003003-00	LER	Generator Bus Ground Caused By Foreign Material Results in Automatic Scram (Section 4OA3.3)
05000277, 278/2002004-01	URI	Licensee's methods and standards used to reactivate staff licensees to support refueling outages appeared to be inconsistent with the requirements of 10 CFR 55.53(f)(2) (Section 1R11)
05000278/2003003-03	URI	Unit 3 HPCI Alternate Control Station Loss of Power (Section 1R15)

Opened and Closed

05000277, 278/2003004-01	NCV	Did Not Meet 10 CFR 55.53(f)(2) When Reactivating Senior Operators to Support Fuel Handling (Section 1R11)
05000277/2003004-02	NCV	Inadequate Corrective Actions on Unit 2 Reactor Core Isolation Cooling Pump for Automatic Flow Control (Section 1R15)
05000277, 278/2003004-04	NCV	Inadequate Emergency Plan Change Documentation, 10 CFR 50.54(q) (Section 1EP4)
0500278/2003004-05	NCV	Deenergized Unit 3 HPCI Alternate Control Station Power Supply (Section 4OA5)

Opened

05000277/2003004-03	URI	Inadequate Corrective Actions for High Unit 2 Steam Tunnel Temperature (Section 1R15)

LIST OF DOCUMENTS REVIEWED

PARTIAL LIST OF DOCUMENTS REVIEWED

Section 2OS1: Occupational Radiation Safety

Procedures:

RP-AA-250, Revision 2	External Dose Assessments from Contamination
RP-AA-350, Revision 1	Personnel Contamination Monitoring, Decontamination and Reporting
RP-AA-400, Revision 2	ALARA Program
RP-AA-400-1002, Revision 0	Dose Equalization
RP-AA-460, Revision 0	Controls for High and Very High Radiation Areas
RP-PB-460-1001, Revision 0	Radiation Protection Controlled Keys

Other Documents

Station ALARA Council Meeting Topics: March17, 2003, June 3, 2003, August 1, 2002, August 26, 2002, December 17, 2002
Cobalt 60 Reduction Strategy
Exposure Reduction Plan - 2003-2005
Five year Rolling Exposure Reduction Plan (2001-2005)
Contingency Plan for Drywell Dose Increase

Section 4OA2: Identification and Resolution of Problems

High Pressure Coolant Injection Lesson Plan (PLORT - 0208D-S)
"System Health Overview Report - HPCI," dated June 2003
SO 23.1.A-3, Revision 12, "High Pressure Coolant Injection System Setup for Automatic or Manual Operation"
SO 13.1.A-3, Revision 11, “RCIC System Alignment for Automatic or Manual Initiation”
COL 23.1.A-3, Revision 18, "High Pressure Coolant Injection System"
LS-AA-125, Revision 5, "Corrective Action Program (CAP) Procedure"
LS-AA-125-1003, Revision 2, "Apparent Cause Evaluation Manual"
LS-AA-125-1006, Revision 4, "CAP Process Expectations Manual"
RT-N-023-240-2, "HPCI Overspeed Trip Test Using Aux Steam," dated September 28, 2002
RT-N-023-240-3, "HPCI Overspeed Trip Test Using Aux Steam," dated September 29, 2001
RT-X-023-210-3, Revision 6, "HPCI Flow Control Stability Test"
ST-O-023-301-3, Revision 33, "HPCI Pump, Valve, Flow and Unit Cooler Functional and In-Service Test"

ST-O-023-301-2, "HPCI Pump, Valve, Flow and Unit Cooler Functional and In-Service Test," dated March 12, 2003, April 30, 2003, June 12, 2003
ST-O-023-301-3, "HPCI Pump, Valve, Flow and Unit Cooler Functional and In-Service Test," dated March 19, 2003, May 9, 2003, June 16, 2003
CM A1373248, "HPCI Turbine Governor Actuator"
Work Order R0474511, ACT 8, "HPCI PVF & Cooler Funct IST Test"
Work Order R0474519, ACT 7, "HPCI PVF & Cooler Funct IST Test"
Technical Specification 3.5.1
UFSAR Sections 6.4.1, 6.5.3.1, 7.4.3.2.4
Peach Bottom Atomic Power Station Units 2 and 3 Individual Plant Examination For External Events, May 1996

<u>Section 1R19 documents reviewed:</u>

ST-I-07G-103-2 “PMT for K-24 Coil Replacement”
ST-O-013-301-3 “RCIC Pump, Valve, and Flow, and Unit Cooler Functional and In-Service Test”
RT-X-013-230-3 “RCIC Flow Control and Turbine Governor Stability Test”

<u>Section 1R20 documents reviewed:</u>

M-18-003, Revision 18, “New Fuel Receipt Inspection”
MA-AA-796-024, Revision 2, “Scaffold Installation, Inspection, and Removal”
OU-AA-101, Revision 4, “Refuel Outage Management”

<u>Section 1R23 documents reviewed</u>:

CC-MA-103-1001, Revision 3, “Implementation of Configuration Changes”
CC-MA-102-1001, Revision 2, “Design Inputs and Impact Screening - Implementation”
LS-AA-104-1000, Revision 1, “Exelon 50.59 Resource Manual”
Work Order A1344857, “A Loop Residual Heat Removal LPCI Injection”
Work Order C0199622, “Restore AO-163A To An Operable Condition”
PBAPS Alarm Response Cards 323 (C-1, C-2, D-2, D-3) and 324 (B-1, B-2)
SO 10.1.A-3, Revision 3, “Residual Heat Removal System Set Up for Automatic Operation”
COL 10.1.A-3A, Revision 15, “Residual Heat Removal System Setup for Automatic Operation Loop A”
P&ID 6280-M-333, Sheet 2, “Instrument Nitrogen”
P&ID 6280-M-361, Sheet 3, “Residual Heat Removal System”
50.59 Screening No. PB-2001-0341-S, Revision 0, for ECR 01-01153
CC-AA-112, Revision 7, “Temporary Configuration Changes”
ST-J-07A-600-3, Revision 3, “Integrated Leak Rate Test”
ST-I-010-100-3, Revision 15, “Residual Heat Removal Loop A Logic System Functional Test”
COL 16.1.A-3, Revision 11, “Instrument Nitrogen System”
COL 7.1.B-3, Revision 17, “Drywell Check Off List (Elevation 135')”
PBAPS 2 & 3 IST Program Cold Shutdown Test Justification 10-VCS-01
UFSAR Sections 4.8, 5.2.4.8, 6.5.3.4
Technical Specifications 3.3.3.1, 3.5.1, 3.6.1.3
Third 10-Year Interval Inservice Testing Program for Pumps and Valves, Peach Bottom Atomic Power Station, Units 2 and 3 (TAC Nos. M98850 and M98851), dated May 11, 1998

Section 1EP2 documents reviewed:

EP-AA-1000, Standard Emergency Plan, Revision 14
EP-AA-1007, Peach Bottom Annex Plan, Revision 3
LS-AA-125, Corrective Action Program, Revision 5
LS-AA-127, Passport Action Tracking, Revision 3
LS-AA-125-1006, CAP Process Expectations, Revision 4
LS-AA-126, Self Assessment Program, Revision 3
NO-AA-200-002, NOS Audit Procedure, Revision 1
LS-AA-106, Plant Operations Review Committee (PORC), Revision 0
PORC 02-101, PORC Meeting Minutes, April 9, 2002
PORC 02-016, PORC Meeting Minutes, June 7, 2002
PORC 02-018, PORC Meeting Minutes, August 23, 2002
EP-AA-121-1001, Automated Call-out System Maintenance
EP-AA-122-1001, Conduct of call-in drills
LS-AA-126, Self Assessment Program, Revision 3
LS-AA-126-1001, Focus Self Assessment, Revision 1
CR 00144433, NOS concluded a declining trend in EP
CR 00140568, EP offsite agency issues
CR 00161234, Less than adequate guidance for the issuance for public information brochures
CR 00161298, Timeliness of drill result evaluation and disposition for MAROG facilities
CR 00123790, 8/22/02 drill - drill management issues
CR 00157056, PB drive in drill performance problems at EOF/JPIC
CR 00138788, EP corrective action deficiencies
CR 00100813, Ineffective management oversight of 2/14/02/drill
CR 00145873, Action plan for improving EP overall performance to white
CR 00122084, 8/16/02 DEP drill procedure and process critique items
CR 00124952, SW bug cause confusion in figuring siren PI data
CR 00161469, CR 110334 evaluation some responses less than adequate
CR 00110614, Training for engineers on the new EP plan was poor
CR 00089064, ENC did not obtain accurate and timely information from EOF
CR 00160985, EP corrective action deficiencies
CR 00161171, EP personnel stated concerns
CR 00161280, Independent review of siren maintenance enhancement
CR 00161298, Untimely EP drill result evaluation and disposition
CR 00100834, DCC assessment recommendations
CR 00116997, PB standard plan drill enhancements - drill/scenario conduct

Section 4OA5 documents reviewed

NUREG/CR-4550, Vol. 4, Rev 1, Part 3, Analysis of Core Damage Frequency: Peach Bottom, Unit 2 External Events, SANDIA, December 1990
Fire PRA Implementation Guide, ERPI, December 1995
NUREG-1742 Vol. 1, Perspectives Gained from the Individual Plant Examination of External Events (IPEEE) Program
RES/OERAB/S02-01 Vol. 1, Fire Events - Update of U.S. Operating Experience, 1986 - 1999, dated January 2002
Fire Induced Vulnerability Evaluation (FIVE), EPRI, April 1992
NUREG 1150 Vol. 1, Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants.

LIST OF ACRONYMS

ACE	apparent cause evaluation
ALARA	as low as is reasonably achievable
ANS	alert and notification system
AR	assignment reports
A/R	action request
ASP	alternate shutdown panel
CFR	Code Of Federal Regulations
CHR	containment heat removal
CR	condition report
DEP	drill and exercise performance
DIE	decrease in the effectiveness
EAL	emergency action level
ECR	engineering change request
EDG	emergency diesel generator
EP	emergency preparedness
ERO	emergency response organization
FPP	fire protection plan
HPCI	high pressure coolant injection
HPSW	high pressure service water
HRA	high radiation area
I&C	Instrumentation and Control
ICMs	interim compensatory measures
IPEEE	individual plant examination of external events
LCO	limiting condition for operation
LPI	low-pressure injection
LSRO	limited senior reactor operator
LTA	less than adequate
MSIV	main steam isolation valves
NCV	non-cited violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation, Office of
PBAPS	Peach Bottom Atomic Power Station
PI	performance indicator
P&ID	piping and instrument diagram

PORC	Plant Operations Review Committee
RCS	reactor coolant system
RHR	residual heat removal
RCIC	reactor core isolation cooling
SBLC	standby liquid control
SBGT	standby gas treatment
SDP	significance determination process
SLC	standby liquid control
SRO	senior reactor operator
SSC	structures, systems and components
ST	surveillance test
SW	service water
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
V	volt