November 6, 2002

Mr. John Skolds
President and CNO
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
5th Floor
Warrenville, IL 60555

SUBJECT: OYSTER CREEK GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 50-219/02-07

Dear Mr. Skolds:

On September 28, 2002, the NRC completed an integrated inspection at your Oyster Creek reactor facility. The enclosed report presents the results of that inspection. The results of this inspection were discussed on October 15, 2002, with Mr. Ernie Harkness and other members of your staff.

This 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 operating license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the inspectors identified two issues of very low safety significance (Green). These findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because the issues were entered into your corrective action 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 these non-cited violations, 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 Oyster Creek facility.

The NRC has increased security requirements at Oyster Creek in response to terrorist acts on September 11, 2001. Although the NRC is not aware of any specific threat against nuclear facilities, the NRC issued an Order and several threat advisories to commercial power reactors to strengthen licensees' capabilities and readiness to respond to a potential attack. The NRC continues to inspect the licensee's security controls and its compliance with the Order and current security regulations.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure 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.html (the Public Electronic Reading Room). We appreciate your cooperation. Please contact me at 610-337-5146 if you have any questions regarding this letter.

Sincerely,

/RA by Richard J. Barkley Acting For/

John F. Rogge, Chief
Projects Branch No. 7
Division of Reactor Projects

Docket No. 50-219
License No. DPR-16

Enclosure: Inspection Report 50-219/02-07
Attachment 1: Supplemental Information

cc w/encl: AmerGen Energy Company - Correspondence Control Deck
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Vice President - Oyster Creek
Licensing and Regulatory Affairs- Vice President, Exelon Corporation
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U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.:	50-219
License No.:	DPR-16
Report No:	50-219/02-07
Licensee:	AmerGen Energy Company, LLC (AmerGen)
Facility:	Oyster Creek Generating Station
Location:	Forked River, New Jersey
Dates:	June 30, 2002 - September 28, 2002
Inspectors:	Robert Summers, Senior Resident Inspector Steve Dennis, Resident Inspector Frederick Jaxheimer, Reactor Inspector Jennifer Bobiak, Project Engineer Steve Shaffer, Project Engineer Jason C. Jang, Senior Health Physicist Nancy McNamara, EP Specialist
Approved By:	John F. Rogge, Chief Projects Branch 7 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000219-02-07; AmerGen Energy Company, LLC; on 06/30-09/28/02; Oyster Creek Generating Station; permanent plant modifications, identification and resolution of problems.

The inspection covered a thirteen-week period and was conducted by resident and region-based inspectors. There were two green findings during this inspection. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using 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. Inspector Identified Findings

Cornerstone: Barrier Integrity

- **GREEN.** The inspectors identified a Non-Cited Violation of Oyster Creek Technical Specification 6.8, Procedures and Programs. The inspectors found that AmerGen failed to maintain procedures No. 317, Feedwater System, and No. 202.1, Power Operation, following the installation of the Digital Average Power Range Monitor Flow Control Trip Reference Card permanent modification (Engineering Change Request 01-01193), which occurred during the week of September 1, 2002. Specifically, the feedwater system procedure was not revised to reflect a maximum core flow limitation, as prescribed in the vendors’ analysis that was referenced in the 10 CFR 50.59 evaluation for the modification installation. This finding was considered to have very low safety significance using the SDP Phase 1 assessment, the inspector’s review of immediate and subsequent corrective actions, and a review of control room logs in which the inspector verified that the maximum core flow limitation was not exceeded. (Section 1R17)

Cornerstone: Mitigating Systems

- **GREEN.** The inspectors identified a non-cited violation of 10 CFR 50 App. B criterion XVI. AmerGen corrective actions for controlling accumulator pressure on the Control Rod Drive System Hydraulic Control Units did not prevent recurrence of the problem. Specifically, corrective actions taken in January 2002 to prevent exceeding the pressure limit permitted by Procedure 302.1, “Control Rod Drive System,” were ineffective in preventing recurrence of the issue on July 25, 2002. This finding was considered to have very low safety significance using the SDP Phase 1 assessment and the inspector’s review of immediate and subsequent corrective actions. (Section 4OA2)

B. Licensee Identified Violations

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 extended into the licensee’s corrective action program. These violations and corrective actions tracking numbers are listed in Section 4OA7 of this report.

Report Details

Summary of Plant Status:

Oyster Creek began the inspection period at full power. On several occasions, reactor power was decreased for a brief period of time to comply with thermal discharge limits or for control rod and recirculation flow adjustments. The lowest power level reached during these occasions was 86 percent. During the first week of September 2002, the licensee installed the Digital Average Power Range Monitor Flow Control Trip Reference Card permanent modification (discussed in section 1R17) to allow for improved operational flexibility and core efficiency prior to the refueling coastdown. On September 12, 2002, a coastdown to the refueling outage began due to fuel burnout. The outage is scheduled to begin on October 4, 2002.

1. REACTOR SAFETY
Initiating Events/Mitigating Systems/Barrier Integrity [REACTOR - R]

1R04 Equipment Alignment

a. Inspection Scope

Equipment alignment partial system walkdown inspections were performed to evaluate the operability of the below listed systems. The inspectors walked down the equipment, reviewed a selected sample of breakers and accessible valves, and verified proper alignment for standby readiness in accordance with operating procedures, technical specifications, the updated final safety analysis report, and associated system drawings. Control room indications and controls were verified to be appropriate for the standby or operating status of the system and system maintenance action requests were reviewed to assure no degraded conditions existed to adversely affect operability. The inspectors reviewed critical components to identify any discrepancies which could affect operability of the system. Minor discrepancies were discussed with licensee personnel for resolution.

- Core Spray System 1, July 15, 2002 to July 17, 2002
- Emergency Service Water System 1 and Containment Spray System 1, July 5, 2002
- Safety-related Equipment Verification (Control Rod Drive, Instrument Air, 125V DC, 480V AC), September 10 and 11, 2002

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted fire protection inspection activities consisting of plant walkdowns, discussions with fire protection personnel, and reviews of procedure 333, “Plant Fire Protection System,” and the Oyster Creek Fire Hazards Analysis Report to verify that the fire program was implemented in accordance with the conditions stated in the facility license. Plant walkdowns included observations of combustible material control, fire detection and suppression equipment availability, and compensatory measures. The inspectors conducted fire protection inspections in the following areas due to the potential to impact mitigating systems:

- Circulating Water Intake - CW-FA-14, on July 2, 2002
- 480V Switchgear Room - OB-FA-6, on July 2, 2002
- Turbine Building Basement - TB-FZ-11D, on August 1, 2002
- 4160V Switchgear Room - TB-FZ-11C, on August 1, 2002
- Main Transformer and Condensate Area - MT-FA-12, on August 21, 2002
- Reactor Building 51' and 75' Elevations - RB-FZ-1C and 1D, on September 9, 2002

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspector reviewed the Oyster Creek Individual Plant Examination of External Events (IPEEE) Section 5.2, "External Floods," Technical Specifications, Integrated Plant Safety Assessment Report (IPSAR - NUREG-0822 Supplement 1), and the Updated Final Safety Analysis Report (UFSAR) concerning internal flooding events. The inspector performed a walkdown of the containment spray pump rooms, reviewed procedures and associated correction documents associated with the 1-6 and 1-7 sumps located in the spray pump corner rooms. The inspector verified that the reactor building floor drain system and operable associated sumps would ensure continued operability of the containment spray and core spray pumps for internal flooding events. In addition, the inspector reviewed corrective action program report (CAP) O2002-1284, which evaluated the operability of the floor drain system and 1-7 sump due to an accumulation of water in the northwest core spray pump room. The inspector also verified proper maintenance of the corrective actions implemented to install a 6-inch sill at the entrance to the emergency diesel generator building.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspector reviewed documents associated with testing, inspection, cleaning and performance trending of the Containment Spray System 1 and 2 Heat Exchangers. The documents reviewed included the Containment Spray System Heat Exchanger Performance Evaluation Calculations (No. C-1302-241-E120-085) and the Updated Final Safety Analysis Report. These heat exchangers were chosen based on their importance in supporting required safety functions in the plant specific risk assessment. The inspector also reviewed corrective action program documents concerning heat exchanger performance issues to verify that the licensee had an appropriate threshold for identifying issues and entering them in the corrective action program. The inspector also evaluated the effectiveness of the corrective actions for identified issues, including the engineering justification for operability, if applicable.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed an operating crew during a requalification examination on the simulator on August 28, 2002. The inspectors evaluated crew performance in the areas of:

- Clarity and formality of communications;
- ability to take timely, appropriate, and safe actions;
- prioritization, interpretation, and verification of alarms;
- procedure use;
- control board manipulations;
- oversight and direction from supervisors; and
- group dynamics.

The inspectors compared crew performance in the above areas to the licensee management expectations, guidelines and critical tasks specified in Oyster Creek Procedure 2611-PGD-2612, “OC Licensed Operator Requalification Training Program.” The inspectors also compared simulator configurations with actual control room board configurations and observed licensee evaluators to verify that they noted weaknesses observed by the inspectors and discussed them in the critique at the end of the session.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors reviewed the licensee’s implementation of the maintenance rule as described in Oyster Creek procedure ER-AA-310, “Implementation of the Maintenance Rule.” The inspectors verified that the below listed systems, structures, and/or components (SSCs) were properly classified as (a)(1) in accordance with 10 CFR 50.65. The inspectors reviewed action requests (ARs), corrective action program reports (CAPs), engineering change requests (ECRs) and (a)(1) corrective action plans. The inspectors also compared unavailability data with control room log entries to verify compliance with (a)(1) goals. Exelon’s trending data were also reviewed. The SSCs reviewed were:

- Service Water System - the week of September 23, 2002.
- 480 Volt AC System - the week of September 23, 2002.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluation

.1 Service Air Emergent Work

a. Inspection Scope

On August 1, 2002, an emergent work activity to repair a leak on the No. 1-1 Service Air Compressor (SAC) was commenced. At the time of this emergent work activity, ongoing test and calibration of the Isolation Condenser isolation logic had resulted in the plant operating in increased risk (Yellow) per the licensee's on-line risk management process. The inspector interviewed the Work Week Manager, who was responsible for performing risk assessments for changes or deviations from the planned work week. The inspector determined that the overall risk profile was not adversely affected by the emergent work on the 1-1 SAC. The inspector also observed the administrative controls established in the plant to protect the remaining SAC compressors to prevent an event initiator (loss of station air) while the Isolation Condensers were unavailable due to the scheduled testing activities.

b. Findings

No findings of significance were identified.

.2 Isolation Condenser Level Transmitter Replacement

a. Inspection Scope

On August 3, 2002, a scheduled calibration on level transmitter LT-G0006A for the "A" Isolation Condenser was performed and the licensee found that the transmitter could not be calibrated to meet the required acceptance criteria for operability. The transmitter was replaced with a new transmitter from stock and then calibrated to meet the required acceptance criteria. The inspectors reviewed the CAP O2002-1159 and action request (AR A2033858) associated with the repair, and the risk assessment related to concurrent work being performed. Additionally, the inspectors verified technical specification adherence and that an extent of condition review was performed as part of the corrective actions.

b. Findings

No findings of significance were identified.

.3 Core Spray System 1 - Pump Failure Pressure Switch Replacement

a. Inspection Scope

On September 10, 2002, the Core Spray System 1 pump failure pressure switch replacement and calibration was performed. The inspectors reviewed the risk assessment associated with the switch replacement to ensure that plans and procedures were in place to ensure operability of the redundant train during the planned maintenance. Additionally, the inspectors reviewed other maintenance activities planned for that day to verify that all maintenance activities were accounted for in assessing the daily risk level.

b. Findings

No findings of significance were identified.

.4 Service Water System 1- Check Valve V-3-131 Replacement

a. Inspection Scope

On September 17 - 19, 2002, scheduled maintenance was performed to replace service water system 1 check valve V-3-131. The initial tagging boundaries established by operations to isolate the check valve for replacement proved insufficient due to leak by of one of the boundary valves. The operations department subsequently expanded the tagging boundary to allow work to continue. The inspectors reviewed the initial and expanded tagging boundaries to evaluate their effect on system configuration and plant risk.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions

a. Inspection Scope

On August 19, 2002, the inspectors observed, in the main control room, licensed operators response to an electrical transient caused by an offsite substation transformer fire and subsequent 230 KV line trip. The transient undervoltage condition caused the Augmented Offgas System to trip offline, the loss of Control Room Ventilation Train B, a momentary power loss at the New Rad Waste Building, the transfer of Instrument Panel 4 to the alternate power supply, and other minor effects on the plant. The inspectors verified that the operators used the appropriate alarm response and plant operating procedures, responded to alarms in a timely manner, and communicated clearly during the transient and recovery. Additionally, the inspectors verified that technical specifications were properly addressed and the transient and its effects were documented in the associated CAP No. O2002-1232.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed operability evaluations in order to verify that proper operability determinations were performed for the following items. In addition, where a component was determined to be inoperable, the inspectors verified that the Technical Specification limiting condition for operation were properly addressed.

- On July 2, 2002, the licensee identified that both channels of the Offgas Radiation Monitoring System were reading unusually low by about 15 percent. The inspectors reviewed the initial operability evaluation, dated July 3, the facility Technical Specifications and the Updated Final Safety Analysis Report. Additionally, the inspectors interviewed the system engineer to verify their understanding of the apparent cause for the unexpected performance of the radiation monitor. Based on continuing difficulty with the performance of these two monitors during a several week period in July and August, the licensee provided additional analyses and standing orders for plant operators whenever the monitors' count rate trend was lower than normal steady state conditions by a value of 15 percent or greater. It was subsequently determined through analysis and troubleshooting actions that the offgas radiation monitor was accurately monitoring the sampled offgas, but that minor flow oscillation in the Main Condenser was affecting the short-lived activity contained in the sample. The inspector reviewed these actions and determined that the standing order appropriately addressed all necessary technical specification required actions for the offgas radiation monitoring system. The inspector also verified that several other systems and required Technical Specification surveillance tests provided additional margin during periods when the offgas monitoring system was degraded, including operable main steam line radiation and main stack effluent radiation monitors, and appropriately scheduled offgas and reactor coolant sampling that provided assurance that no unusual radioactive releases occurred.

- During a plant tour on July 23, 2002, the licensee found a pinhole leak on a Service Water System line downstream of the Reactor Building Closed Cooling Water System Heat Exchangers. The inspectors reviewed the initial operability evaluation and the followup evaluation based upon making temporary repairs (TM 2002-023) for the leak. Additionally, the inspectors reviewed the associated 10 CFR 50.59 screening form (OC-2002-S-0427) and applicable sections of the Updated Final Safety Analysis Report (UFSAR).

- The licensee found a leaking check-valve on Fire Pond Pump 1-1 while performing surveillance test ST 645.4.018, "Fire Pump Monitoring Test," on September 6, 2002. The inspectors reviewed the licensee's engineering evaluation regarding the significance of the leakage on fire pump discharge pressure and whether it could impact fire pump operability (CAP O2002-1315). Additionally, the inspectors interviewed the system engineer to verify their understanding of the pump performance deficiency.

- While performing surveillance test ST636.4.013, “Emergency Diesel Generator #2 Load Test,” on September 16, 2002, alarms were received for “Control DC Low/Lost” and “Diesel Generator Over Voltage/Ground.” The operators noted that the alarms cleared immediately, however, no initial cause for the alarms was determined. The inspectors reviewed the initial operability determination and the engineering evaluation regarding continued operability of the diesel as written in CAP O2002-1345. The inspectors also interviewed the system engineer and reviewed the troubleshooting, repair, and retest plan for ensuring continued diesel operability.

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed the operator work-around, challenge, and concern lists to verify that the functional capability of the affected system, human reliability in responding to an initiating event, or the ability of operators to implement abnormal or emergency operating procedures was not significantly affected. The inspectors reviewed the applicable sections of the Updated Safety Analysis Report and Technical Specifications and discussed the work-arounds with the licensed operators. Additionally, the inspectors verified that the methodology used to document the work-arounds, challenges, and concerns was performed in accordance with the Exelon Procedure OP-AA-102-103, “Operator Work-Around Program.”

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

During the week of September 1, 2002, the licensee installed Digital Average Power Range Monitor Flow Control Trip Reference Cards to allow for improved operational flexibility and core efficiency. The inspectors reviewed the engineering evaluation (ECR OC 01-01193), the UFSAR, technical specifications, the environmental qualification document (GE document No. 148C7112G002), the revised Core Operating Limits Report, affected operations procedures, and the installation package for the cards (AR No. A2021967). Additionally, the inspectors interviewed operations and engineering personnel to verify their understanding of the revised limitations on Minimum Critical Power Ratio, feedwater temperature, and recirculation flow. The inspectors also reviewed the impact of the modification on reactor core flow, as it pertained to Final Feedwater Temperature Reduction (FFWTR), which was being implemented coincident with the permanent modification.

b. Findings

Introduction

The inspectors identified a Non-Cited Violation of Oyster Creek Technical Specification 6.8, “Procedures and Programs,” having very low safety significance (Green). The inspectors found that AmerGen failed to maintain Procedure No. 317, “Feedwater System,” and No. 202.1, “Power Operation,” following the installation of the Digital Average Power Range Monitor Flow Control Trip Reference Card permanent modification (Engineering Change Request 01-01193), which occurred during the week of September 1, 2002.

Description

During the week of September 1, 2002, the licensee installed the Digital Average Power Range Monitor Flow Control Trip Reference Cards as a permanent modification to allow for improved operational flexibility and core efficiency. The engineering analysis and 10 CFR 50.59 evaluation (ECR OC 01-01193) associated with the permanent modification limits the maximum core flow rate to 110.7% of rated core flow (67.5 Mlb/hr). The equivalent core flow value of 67.5 Mlb/hr in gallons per minute, as monitored in the main control room and operations procedures, is 17.7 X E4 gpm.

The vendor analysis for the modification, which was referenced in the 10 CFR 50.59 evaluation, imposed a further limitation on reactor core flow of 17.6 X E4 gpm if the FFWTR evolution was implemented by plant operations. The FFWTR evolution, which removes the extraction steam input to the high and intermediate pressure feedwater heaters, is implemented at the end of core life in an effort to maintain core thermal efficiency and electric generation output. The lower core flow limit took into account the water density change caused by FFWTR. Later in September 2002, Oyster Creek implemented FFWTR and the inspectors found that the more restrictive reactor core flow limitation described in the vendor analysis, as referenced in the 10 CFR 50.59 evaluation, had not been incorporated into operations procedures.

The inspectors notified Oyster Creek engineering and operations management of this omission and verified through review of operations logs that the lower core flow limit had not been exceeded after the implementation of FFWTR. The inspectors also noted that a previously issued daily core maneuvering instruction sheet limited reactor core flow, during all reactivity change evolutions, to the vendor analysis limit of 17.6 E4 gpm. Additionally, the inspectors reviewed CAPs O2002-1367 and O2002-1339 and verified that the issue was entered into the corrective action program and affected procedures were immediately revised.

Analysis

The finding is considered more than minor in that the issue was associated with the Barrier Integrity cornerstone and affected procedure quality which could have impacted the reactor coolant system design barrier. The inspectors used Manual Chapter 0609, “Significance Determination Process,” Appendix “A” - “Significance Determination of Reactor Inspection Findings for At-Power Situations,” and determined that:

- the finding was not a design or qualification deficiency;
- the finding did not represent an actual loss of the safety function for any mitigating system and did not result in a loss of function of a single train of any mitigating systems for greater than its TS allowed outage time;
- the finding did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours;
- the finding did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event in that the finding did not involve the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding or severe weather initiating event; and
- the finding did not involve the loss of a safety function that contributed to external event initiated core damage accident sequences.

Additionally, the inspectors found that a previously issued daily core maneuvering instruction sheet limited reactor core flow, during all evolutions, to the vendor analysis limit of 17.6 E4 gpm.

Therefore, the finding screened as Green, very low safety significance.

Enforcement

Oyster Creek Technical Specification 6.8.1 states, in part, that written procedures shall be maintained, as recommended in Appendix “A” of Regulatory Guide 1.33. The Feedwater System and Power Operation procedures are listed in Appendix “A” of Regulatory Guide 1.33.

Contrary to the above, Oyster Creek Procedure No. 317, “Feedwater System,” and No. 202.1, “Power Operation,” were not adequately maintained during the installation of a permanent modification that allowed for increased reactor core flow. Specifically, the feedwater system procedure was not revised to reflect a maximum core flow limitation, as prescribed in the vendor analysis, which was referenced in the 10 CFR 50.59 evaluation for the modification installation.

AmerGen documented this issue in CAP O2002-1367. Because this violation was of very low safety significance and AmerGen entered this finding into its corrective action program, this violation is being treated as a Non-Cited Violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 50-219/02-07-01)**

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspector reviewed and observed portions of the post maintenance testing associated with the following maintenance activities because of their function as mitigating systems and their potential role in increasing plant transient frequency. The inspectors reviewed the post maintenance test documents to verify that they were in accordance with the licensee's procedures and that the equipment was restored to an operable state.

- Containment Spray/Emergency Service Water (ESW) System 1 - accelerated testing on ESW pump 51A due to increased vibration. Surveillance test (ST) 607.4.004, "Containment Spray and Emergency Service Water System 1 Operability and Inservice Test" was performed on July 11, 2002.

- Isolation Condenser A level transmitter calibration- level transmitter LT-IG0006A was replaced and calibrated in accordance with recurring task No. PM 21101I, "A Isolation Condenser level indication Loop Calibration" on August 4, 2002.

- Torus Purge and Vent Containment Isolation Valves V-23-13,14, 15, and 16, limit switch mounting modification. ST 678.4.001, "Primary Containment Isolation Valve Operability and IST" was performed on August 22 and 23, 2002.

- Core Spray System 1- pump failure pressure switch replacement and calibration. ST 610.3.001, "Core Spray Pump Failure Pressure Switches Surveillance Calibration" was performed on September 10, 2002.

- Emergency Service Water/Containment Spray System 1 - installation of a cross tie piping modification between Emergency Service Water and Service Water System 1. ST 607.4.014, "Containment Spray and ESW System1 Pump Operability and In Service Test" was performed on September 20, 2002.

b. <u>Findings</u>

No findings of significance were identified.

1R22 <u>Surveillance Testing</u>

a. <u>Inspection Scope</u>

The inspector observed pre-test briefings and portions of the surveillance test (ST) performance for procedural adherence, and verified that the resulting data associated with the test met the requirements of the plant technical specifications. The inspector also reviewed the results of past performances of the selected STs to verify that degraded or non-conforming conditions were identified and corrected. The following STs were observed:

- Control Rod Drive Pumps A and B, operability test performed per procedure, ST 617.4.001, on July 10, 2002
- Electromagnetic Relief Valve Pressure Sensor Test and Calibration performed per procedure, ST 602.3.004, on July 25, 2002

- Iso-Condenser Valve Operability Test, performed per procedure, ST 609.4.001, on July 31, 2002
- Emergency Diesel Generator No. 1 Operability Load Test performed per procedure, ST 636.4.003, on August 26, 2002
- Core Spray Isolation Valve Actuation Test and Calibration, performed per procedure, ST 610.3.006, on September 9, 2002

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

On July 10, 2002, the inspectors reviewed a temporary modification installed under AR No. A2036939, which addressed a failed motor on the C Battery Room Exhaust Control Damper (DM-59-7). Per the temporary modification, the damper was gagged in the open position until the motor was repaired. The inspectors also walked down the temporary modification installation and reviewed the associated 10 CFR 50.59 screening report, system procedures, technical specifications, and the associated sections of the UFSAR. Additionally, the inspectors verified that the modification was performed in accordance with OC Procedure 108.8, "Temporary Modification Control."

b. Findings

No findings of significance were identified.

Emergency Preparedness [EP]

1EP2 Alert Notification System (ANS)Testing

a. Inspection Scope

An onsite review of the licensee's ANS was conducted to ensure prompt notification of the public to take protective actions. The inspector reviewed: (1) the licensee's approved ANS design basis document entitled, "Prompt Notification System Design Report" submitted to the Federal Emergency Management Agency (FEMA); (2) siren testing data; and (3) maintenance records for correcting siren failures. In addition, the inspector interviewed the ANS Communication Program Manager responsible for maintaining the ANS and reviewed procedure OEP-ADM-1319.04, "Prompt Notification System," Rev. 4. 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.

Two CAPs (listed in Attachment 1) were reviewed during the inspection and entered into the corrective action program to address inspector observations during the ANS portion of this inspection.

b. Findings

Between the time frame of 1987-1989, the licensee had removed five offsite sirens covering the southern tip of Long Beach Island, New Jersey, which were required per the licensee's ANS Prompt Notification System Design Report, submitted and approved by FEMA and the NRC in 1986. The sirens were located outside the 10-mile Emergency Planning Zone (EPZ) and were removed from their Emergency Plan. The State of New Jersey, Office of Emergency Management, had agreed to the removal of the sirens but the licensee has no record that the removal was discussed with FEMA or the NRC. In addition, the licensee was not able to locate the 10 CFR 50.54(q) review for determining if the removal of the sirens had decreased the effectiveness of the Emergency Plan. A further review of the design basis document found that 58 tone alert radios, used to complement the ANS, were removed from the Emergency Plan sometime in late 1989. According to the licensee, FEMA had granted approval to remove similar type radios around another nuclear power plant located in the State of New Jersey and the State assumed it was a "blanket" approval for all nuclear power plants. The State requested the licensee remove the radios. However, there is no record that the licensee informed FEMA or the NRC and no 10 CFR 50.54(q) review was conducted for determining if a decrease of the effectiveness of the Plan had occurred. This issue is considered an Unresolved Item **(URI 50-219/02-07-02)** pending a review by FEMA to determine if: (1) the sirens located on the southern tip of Long Beach Island were an integral part of the ANS; and (2) maintenance and testing of the tone alert radios was allowed to be discontinued. When the review is complete, the NRC will assess FEMA's response and determine the significance of this issue.

1EP3 Emergency Response Organization (ERO) Augmentation Testing

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 the licensee's Emergency Plan qualification records for key ERO positions, monthly communication pager test records, and associated condition reports regarding on-call ERO not responding to the quarterly pager tests. The inspector reviewed OEP-SUR-1410.09, "Emergency Communication Surveillance"; (2) EPIP-OC-.41, "Emergency Duty Roster"; and (3) 2612-PGD-2685, "Emergency Preparedness Training Program," Rev. 2. 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) and Emergency Plan Changes

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 January through July 2002. Onsite, the inspector reviewed the associated 10 CFR 50.54(q) reviews. 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

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

a. Inspection Scope

The inspector reviewed corrective actions identified by the licensee pertaining to findings from drill/exercise reports for 2000 and 2001, self-assessment reports for 2002 and from problems resulting from surveillance tests and actual events. CAPs assigned to the EP Department were also reviewed to determine the significance of the issues and to determine if repeat problems were occurring. In addition, the inspector reviewed the 2001 and 2002 quarterly Nuclear Oversight audit reports and the associated audit checklists to determine if the licensee had met the 10 CFR 50.54(t) requirements and if any repeat issues were identified. 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

a. Inspection Scope

On August 28, 2002, the inspector observed a licensed operator training assessment that included an emergency activation level classification. The inspector verified that the appropriate emergency classification was identified and external notifications to responsible parties were made in a timely manner.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY
Public Radiation Safety [PS]

2PS3 Radiological Environmental Monitoring Program (REMP)

.1 REMP Effectiveness

a. Inspection Scope

The requirements of the REMP were specified in the Technical Specification/Offsite Dose Calculation Manual (TS/ODCM). The inspector reviewed the following documents to evaluate the effectiveness of the licensee's REMP:

- the 2000/2001 Annual REMP Reports, including selected analytical data for 2002 REMP samples;
- upgrading process of the most recent ODCM (Revision 14) and technical justifications for ODCM changes, including sampling locations;
- the most recent calibration results of the primary (33-ft, 150-ft, and 380-ft) and the redundant (33-ft and 380-ft) meteorological monitoring instruments for wind direction, wind speed, and delta temperature;
- availability of the meteorological monitoring instruments from January 1, 2001, to May 31, 2002;
- review of calibration procedure and the most recent calibration results for all TS/ODCM required air samplers;
- implementation of the environmental thermoluminescent dosimeters (TLDs) program, including transit dose calculation;
- the licensee's QC evaluation of the inter-laboratory and intra-laboratory comparison program and the corrective actions for any deficiencies;
- 2001 QA Surveillance (NOA-OC-01-1Q) for the REMP and the Meteorological Monitoring Program implementations;
- the Land Use Census procedure and the 2000/2001 results; and
- associated REMP procedures, including vendor's analytical procedures.

The inspector toured and observed the following activities to evaluate the effectiveness of the licensee's REMP:

- operability of the primary and redundant meteorological instruments;
- charcoal cartridge and filter sampling techniques; and
- walkdown to determine: (1) if air samplers and TLDs were located as described in the ODCM (including control and indicator stations), and (2) the material condition of the equipment.

b. Findings

No findings of significance were identified.

.2 Radioactive Material Control Program

a. Inspection Scope

The inspector reviewed the following documents and observed licensee activities to ensure that the licensee’s surveys and controls were adequate to prevent the inadvertent release of licensed material to the public domain:

- the methods used for control, survey, and release from the Radiologically Controlled Area (RCA);
- the most recent calibration results for the radiation monitoring instrumentation (small articles monitor, SAM-9 and SAM-11), including the (1) alarm setting, (2) response to the alarm, (3) the sensitivity, and (4) alarm failure rate;
- the use of SAM-9 and SAM-11 instruments by employees;
- the most recent calibration results for the gamma measurement system used in the material control program;
- the licensee’s criteria for the survey and release of potentially contaminated material; and
- associated procedures and records to verify for the lower limits of detection.

The review was against criteria contained in: (1) NRC Circular 81-07, “Control of Radioactively Contaminated Material”; (2) NRC Information Notice 85-92, “Surveys of Waste before Disposal from Nuclear Reactor Facilities”; and, (3) NUREG/CR-5569, “Health Position Data Base (Positions 221 and 250).”

b. Findings

No findings of significance were identified.

3. SAFEGUARDS
Physical Protection [PP]

3PP3 Response to Contingency Events

The Office of Homeland Security (OHS) developed a Homeland Security Advisory System (HSAS) to disseminate information regarding the risk of terrorist attacks. The HSAS implements five color-coded threat conditions with a description of corresponding actions at each level. NRC Regulatory Information Summary (RIS) 2002-12a, dated

August 19, 2002, “NRC Threat Advisory and Protective Measures System,” discusses the HSAS and provides additional information on protective measures to licensees.

a. Inspection Scope

On September 10, 2002, the NRC issued a Safeguards Advisory to reactor licensees to implement the protective measures described in RIS 2002-12a in response to the Federal government declaration of threat level “orange.” Subsequently, on September 24, 2002, the OHS downgraded the national security threat condition to “yellow” and a corresponding reduction in the risk of a terrorist threat.

The inspector interviewed licensee personnel and security staff, observed the conduct of security operations, and assessed licensee implementation of the threat level “orange” protective measures. Inspection results were communicated to the region and headquarters security staff for further evaluation.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator (PI) Verification

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors reviewed the Oyster Creek performance indicator (PI) data against applicable criteria specified in Nuclear Energy Institute (NEI) 99-02, to verify that all conditions that met the NEI criteria were recognized and identified as PI occurrences. The inspectors verified the accuracy of the reported data through reviews of monthly operating reports, shift operating logs, Licensee Event Reports (LERs) and other station records. The inspectors reviewed 12 months of reported data (July 2001 - June 2002) for the Safety System Functional Failure PI.

The inspector identified that LER 50-219/2002-01, “Plant Operations Outside of the Technical Specifications due to a Degraded System,” describes an event where the Offgas Radiation Monitor was not capable of performing its intended function of isolating the offgas line if Technical Specification Release Limits were exceeded. While the licensee reported this condition under 10 CFR 50.73(a)(2)(i), an operational condition prohibited by the plant Technical Specifications, the inspector questioned if this event should have also been reportable under 10 CFR 50.73 (a)(2)(v), an event that could have prevented the fulfillment of a safety function that is needed to control the release of radioactive material. If so, the failure of the Offgas Radiation Monitoring System could be considered a Safety System Functional Failure per the guidance in NEI 99-02. The inspector documented this possible PI calculation error in a feedback form and submitted it to NRC headquarters for further review.

Regardless of whether this LER constitutes a safety system functional failure or not, there would be no PI threshold change and the PI would remain Green.

b. Findings

No findings of significance were identified.

.2 Emergency Preparedness

a. Inspection Scope

The inspector reviewed the licensee's procedure for developing the data for the EP PIs which are: (1) Drill and Exercise Performance (DEP); (2) ERO Drill Participation; and (3) ANS Reliability. The inspector also reviewed the licensee's drill/exercise reports, training records and ANS testing data since the last NRC PI inspection, conducted in December 2001, to verify the accuracy of the reported data. The review was conducted in accordance with NRC Inspection Procedure 71151. The acceptance criteria used for the review were 10 CFR 50.9 and NEI 99-02, Revision 1, Regulation Assessment Performance Indicator Guideline.

Also, four CAPs were reviewed by the inspector. These corrective action program reports addressed licensee identified errors found in their reported PI data that needed correction. The CAPs are listed in Attachment 1 to this report.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Reactor Safety

a. Inspection Scope

During the course of the inspection period while conducting the inspection activities described in this report, a sample of issues identified on the structures, systems, and components at the plant were reviewed for proper handling per the licensee's corrective action program. The licensee's method for identifying the problem, determining how long the problem existed, and determining the plant-specific risk consequences, as well as actions taken to evaluate the root causes, extent of condition, and associated corrective actions were assessed. Issues selected for review by the inspectors are listed in Attachment 1 of this report, identified by CAP number. During the course of this review, the inspector identified a finding associated with ineffective corrective actions for the Control Rod Drive System. That issue is discussed in paragraph (.2) below.

b. Findings

No findings of significance were identified.

.2 Control Rod Drive System

a. Inspection Scope

The inspectors performed a plant status walkdown in the reactor building on July 25, 2002. During the walkdown the inspectors assessed the status of ongoing maintenance and testing activities, protective measures associated with operable system trains, and the standby status of safety systems with previously identified deficiencies. The Control Rod Drive System was included in the walkdown.

b. Findings

Introduction

The inspectors identified a Non-Cited Violation of 10 CFR 50 App. B Criterion XVI having very low safety significance (Green). AmerGen corrective actions for controlling accumulator pressure on the Control Rod Drive System Hydraulic Control Units did not prevent recurrence of the problem. Specifically, corrective actions taken in January 2002 to prevent exceeding the pressure limit permitted by procedure 302.1, “Control Rod Drive System,” were ineffective in preventing recurrence of the issue on July 25, 2002.

Description

On January 25, 2002, AmerGen identified that the accumulator pressure on 11 Control Rod Drive System Hydraulic Control Units exceeded the maximum pressure (1150 psig) permitted by procedure No. 302.1, “Control Rod Drive System.” The issue was placed into the corrective action program at that time and actions were taken to revise system procedures to prevent recurrence. During a plant walkdown on July 25, 2002, the inspectors found that accumulator pressure on 38 Control Rod Drive System Hydraulic Control Units again exceeded the maximum pressure permitted by procedure. The highest pressure observed was about 1250 psig.

The inspectors notified AmerGen operations and engineering of the finding and verified the immediate actions taken by the licensee to correct the problem. The inspectors also reviewed and verified subsequent procedural corrective actions. Additionally, the inspectors reviewed the engineering operability evaluation that addressed the effects of higher pressure on the hydraulic control unit accumulators. The evaluation determined that the higher pressures found on the accumulators did not exceed design system pressure (1500 psig) and therefore did not affect the ability to perform the intended safety function. The evaluation also stated that if left uncorrected, long term effects of the high pressure condition could result in control rod drive mechanism seal degradation.

Analysis

AmerGen corrective actions for controlling accumulator pressure on the Control Rod Drive System Hydraulic Control Units did not prevent recurrence of the problem and is considered a performance deficiency. Specifically, corrective actions taken in January

2002 to prevent exceeding the pressure limit permitted by procedure 302.1, “Control Rod Drive System,” were ineffective in preventing recurrence of the issue on July 25, 2002.

The finding is considered more than minor in that the issue was associated with the Mitigating Systems cornerstone and was a recurrence of an issue that could affect the long term reliability of the Control Rod Drive Hydraulic Accumulators if left uncorrected. The inspectors used Manual Chapter 0609, “Significance Determination Process,” Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” regarding mitigating systems and determined that:

- the finding was not a design or qualification deficiency;

- the finding did not represent an actual loss of the safety function for any mitigating system and did not result in a loss of function of a single train of any mitigating systems for greater than its TS allowed outage time;

- the finding did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant per 10 CFR 50.65 for greater than 24 hours;

- the finding did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event in that the finding did not involve the loss or degradation of equipment or function specifically designed to mitigate a seismic, flooding or severe weather initiating event; and

- the finding did not involve the loss of a safety function that contributed to the external event initiated core damage accident sequences.

Therefore, the finding screened as Green, very low safety significance.

Enforcement

10 CFR 50 App. “B” Criterion XVI states, in part, “measures shall be established to assure conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, and nonconformances are promptly identified and corrected.”

Contrary to the above, AmerGen’s corrective actions taken in January 2002, to ensure Control Rod Drive Hydraulic Control Units accumulator pressure remained within required procedural limits, did not correct the procedural non-conformance as evidenced by recurrence of the issue on July 25, 2002.

AmerGen documented this issue in CAP O2002-1089. Because this violation was of very low safety significance and AmerGen entered this finding into its corrective action program, this violation is being treated as a Non-Cited Violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 50-219/02-07-03)**

.3 Radiation Safety

a. Inspection Scope

The inspector reviewed a selection of 25 CAPs associated with the meteorological monitoring program, radioactive material control program, and the ODCM/REMP program to evaluate the effectiveness of the licensee's problem identification and resolution processes. These CAPs are listed in Attachment 1 of this report. In addition, the inspector reviewed the 2002 Self-Assessment Report for the REMP program.

b. Findings

No findings of significance were identified.

4OA3 Event Followup

.1 (Closed) LER 50-219/02-001-00 Plant Operations Outside of the Technical Specifications due to a Degraded System

On April 25, 2002, Oyster Creek identified that Offgas Radiation Monitoring System had been inoperable due to moisture intrusion into the detector sample chamber for a period of about 17 days beginning March 23, 2002. This exceeded the allowable out of service time of 72 hours described in the facility Technical Specifications. This event is further discussed in Section 4OA7 of this report.

4OA6 Meetings, Including Exit

.1 Exit Meeting Summary

On October 15, 2002, the resident inspectors presented the inspection results to Mr. Ernie Harkness and other members of licensee management. The inspector also reviewed issues previously discussed at an interim exit meeting conducted by region-based inspectors on August 16, 2002. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

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

- Technical Specification Table 3.1.1, Protective Instrumentation Requirements, item I, Offgas System Isolation, requires the plant to be in a shutdown condition if both offgas detectors are inoperable for greater than 72 hours. On April 9, 2002, the licensee identified that water intrusion into the offgas sample chamber, caused by a failure of the system heat tracing, had rendered both detectors inoperable. Further analysis by licensee engineering revealed that the detectors had been inoperable since March 26, 2002, a period greater than the allowable 72 hours, also during which full power operations were maintained. This was a violation of the Technical Specification. This issue has greater significance than a similar issue described in Inspection Manual Chapter 0612, Appendix E, Section 2.f. The issue was not considered to be greater than green because while both detectors were inoperable, alternate effluent gas monitoring was available to detect plant effluent releases through the plant stack radioactive gaseous effluent monitoring system, and weekly chemistry samples of both reactor coolant and offgas effluent showed no increase in activity, which indicated no releases occurred of sufficient magnitude for this system to automatically isolate the condenser offgas. This issue has been entered into the licensee's corrective action program as CAP O2002-0542 and is described in LER 05000219/2002-001, dated May 23, 2002. Because alternate monitoring capability existed and showed that release limits were not exceeded, this violation is not more than of very low safety significance, and is being treated as a Non-Cited Violation.

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

a. Key Points of Contact

Licensee (in alphabetical order)
V. Aggarwal, Director, Engineering
R. DeGregorio, Vice President
E. Harkness, Plant Manager
R. Hillman, Manager, Chemistry & Radwaste
J. Magee, Director, Maintenance
M. Massaro, Director, Work Management
D. McMillan, Director, Training
M. Newcomer, Senior Manager, Design
D. Slear, Manager, Regulatory Assurance
C. Wilson, Senior Manager, Operations

b. List of Items Opened, Closed, and Discussed

Opened

50-219/02-007-02	URI	Sirens and Tone Alert Radios removed from Emergency Plan without prior approval from FEMA and NRC. (Section 1EP2)

Opened and Closed

50-219/02-007-01	NCV	Oyster Creek Technical Specification 6.8.1 states, in part, that written procedures shall be maintained, as recommended in Appendix "A" of Regulatory Guide 1.33. The Feedwater System and Power Operation procedures are listed in Appendix "A" of Regulatory Guide 1.33. Contrary to the above, Oyster Creek procedures No. 317, Feedwater System, and No. 202.1, Power Operation, were not adequately maintained during the installation of a permanent modification which allowed for increased reactor core flow. Specifically, the feedwater system procedure was not revised to reflect a maximum core flow limitation, as prescribed in the vendor analysis for the modification installation which was referenced in the 10 CFR 50.59 evaluation. (Section 1R17)
50-219/02-007-03	NCV	10 CFR 50 App. "B" Criterion XVI states, in part, "measures shall be established to assure conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, and nonconformances are promptly identified and corrected." Contrary to the above, AmerGen's corrective actions taken in January 2002, to

ensure Control Rod Drive Hydraulic Control Units accumulator pressure remained within required procedural limits did not correct the procedural non-conformance as evidenced by recurrence of the issue on July 25, 2002. (Section 4OA2)

50-219/02-001-00	LER	Plant Operations Outside of the Technical Specifications due to a Degraded System (Sections 4OA3.1 and 4OA7)

c. List of Acronyms

ADAMS	Agencywide Documents Access and Management System
ALARA	As Low As Is Reasonably Achievable
AmerGen	AmerGen Energy Company, LLC
ANS	Alert Notification System
AR	Action Request
CAP	Corrective Action Process
CFR	Code of Federal Regulations
DEP	Drill and Exercise Performance
EAL	Emergency Action Level
ECR	Engineering Change Request
EP	Emergency Preparedness
ERO	Emergency Response Organization
ESW	Emergency Service Water
FEMA	Federal Emergency Management Agency
FFWTR	Final Feedwater Temperature Reductions
HSAS	Homeland Security Advisory System
IPEEE	Individual Plant Examination of External Events
LER	Licensee Event Report
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
OC	Oyster Creek
ODCM	Offsite Dose Calculation Manual
OHS	Office of Homeland Security
PI	Performance Indicator
QA	Quality Assurance
QC	Quality Control
RCA	Radiologically Controlled Area
REMP	Radiological Environmental Monitoring Program
RIS	Regulatory Information Summary
SAC	Service Air Compressor
SDP	Significance Determination Process
SSC	Systems, Structures and Components
ST	Surveillance Test
TLD	Thermoluminescent dosimeter
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report

d. List of Corrective Action Program Reports Reviewed:

Attachment 1 (Cont.)

CAP O2001-0117	CAP O2001-0177	CAP O2001-0672	CAP O2001-0860
CAP O2001-1007	CAP O2001-1063	CAP O2001-1156	CAP O2001-1160
CAP O2001-1246	CAP O2001-1396	CAP O2001-1595	CAP O2001-1673
CAP O2001-1695	CAP O2001-1706	CAP O2001-1868	

CAP O2002-0112	CAP O2002-0247	CAP O2002-0280	CAP O2002-0542
CAP O2002-0562	CAP O2002-0811	CAP O2002-1089	CAP O2002-1091
CAP O2002-1101	CAP O2002-1131	CAP O2002-1132	CAP O2002-1159
CAP O2002-1232	CAP O2002-1284	CAP O2002-1315	CAP O2002-1339
CAP O2002-1345	CAP O2002-1367	CAP O2002-1535	