July 18, 2005

Mr. Christopher M. Crane
President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BRAIDWOOD STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000456/2005003; 05000457/2005003

Dear Mr. Crane:

On June 30, 2005, the U. S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Braidwood Station, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on July 7, 2005, with Mr. K. Polson and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and to 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.

On the basis of the results of this inspection, no findings of significance were identified.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made 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).

Sincerely,

/RA/

George Wilson, Acting Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50-456; 50-457
License Nos. NPF-72; NPF-77

Enclosure: Inspection Report 05000456/2005003; 05000457/2005003
w/Attachment: Supplemental Information

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REGION III

Docket Nos:	50-456; 50-457
License Nos:	NPF-72; NPF-77
Report No:	05000456/2005003; 05000457/2005003
Licensee:	Exelon Generation Company, LLC
Facility:	Braidwood Station, Units 1 and 2
Location:	35100 S. Route 53 Suite 79 Braceville, IL 60407-9617
Dates:	April 1 through June 30, 2005
Inspectors:	S. Ray, Senior Resident Inspector N. Shah, Senior Resident Inspector L. Haeg, Acting Resident Inspector B. Jorgensen, Consultant R. Ruiz, Acting Resident Inspector M. Jordan, Consultant T. Tongue, Project Engineer R. Daly, Reactor Engineer M. Holmberg, Reactor Engineer J. House, Senior Radiation Specialist P. Lougheed, Senior Reactor Inspector C. Phillips, Senior Operations Engineer C. Roque-Cruz, Reactor Engineer J. Roman, Illinois Emergency Management Agency
Approved by:	George Wilson, Acting Chief Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000456/2005003, 05000457/2005003; 04/01/2005 - 06/30/2005; Braidwood Station, Units 1 & 2; Routine Integrated Inspection Report.

This report covers a 3-month period of baseline resident inspection, routine baseline inspection activities, announced baseline inspections on radiation protection and effluent controls, and Temporary Instructions 2515/150, 2515/160 and 2515/163. The inspection was conducted by resident inspectors, regional engineering specialists, a regional health physics inspector, contractors, and a regional plant support specialist. No findings of significance were identified. 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 and Self-Revealed Findings

Cornerstone:

No findings of significance were identified.

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power for the entire inspection period.

Unit 2 started the inspection period in a forced outage due to a generator bushing failure that occurred on March 31, 2005. On April 2, 2005, Unit 2 was returned to full power. Unit 2 continued to operate at full power until April 17, 2005, when it was shutdown for a scheduled refueling outage (A2R11). On May 7, 2005, Unit 2 was returned to full power. Unit 2 continued to operate at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed the licensee's seasonal preparations for operation during the summer months. This was primarily accomplished by verifying that the licensee had completed the requirements for summer readiness as documented in Exelon Nuclear Procedure OP-AA-108-109, "Seasonal Readiness," Revision 1. The inspectors also reviewed the Updated Final Safety Analysis Report (UFSAR), Technical Specifications (TS) and other design-bases documents to identify those components that were "at risk" during the summer months due to high temperatures. The inspectors verified that the licensee had addressed these components in preparation for summer operation. In addition, the inspectors selected the following risk-significant support systems/areas for specific review:

- Units 1 and 2 miscellaneous electrical equipment and engineered safety feature Division 11, 12, 21 and 22 rooms;
- lake screen house and turbine building general areas; and
- 2B and 2D outside main steam isolation valve rooms.

This review constituted one sample of this inspection requirement.

The inspectors also reviewed several condition reports (CRs) documenting problems with heat exchangers, room temperatures, or adverse weather control, to determine whether these issues were being properly addressed in the licensee's corrective action program. The inspectors also verified that minor issues identified during these inspections were entered into the licensee's corrective action program. Documents reviewed as part of this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdowns

a. Inspection Scope

The inspectors performed partial walkdowns of the accessible portions of risk-significant system trains during periods when the train was of increased importance due to redundant trains or other equipment being unavailable. The inspectors utilized the valve and electric breaker checklists listed to determine whether the components were properly positioned and that support systems were aligned as needed. The inspectors also examined the material condition of the components and observed operating parameters of equipment to determine whether there were any obvious deficiencies. The inspectors reviewed CRs associated with the train to determine whether those documents identified issues affecting train function. The inspectors used the information in the appropriate sections of the TS and the UFSAR to determine the functional requirements of the system. The inspectors also reviewed the licensee's identification of and the controls over the redundant risk-related equipment required to remain in service. Documents reviewed during this inspection are listed in the Attachment.

The inspectors completed three samples of this requirement by walkdowns of the following trains:

- 0A train of control room ventilation;
- 2A train of essential service water (SX); and
- 1A emergency diesel generator.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Inspection

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of fire fighting equipment, the control of transient combustibles and ignition sources, and on the condition and operating status of installed fire barriers. The inspectors selected fire areas for inspection based on their overall contribution to internal fire risk, as documented in the Individual Plant Examination of External Events with later additional insights or their potential to impact equipment which could initiate a plant transient or be required for safe shutdown. The inspectors used the Fire Protection Report, Revision 21, to determine: whether fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and that fire doors, dampers, and penetration seals appeared to be in satisfactory condition.

The inspectors completed nine samples of this inspection requirement during the following walkdowns:

- observations of hotwork in the turbine building during the Unit 2 refueling outage;
- 2 A and 2B trains of the residual heat removal system;
- Unit 1 diesel driven auxiliary feedwater pump room (Fire Zone 11.4A-1);
- Unit 2 diesel driven auxiliary feedwater pump room (Fire Zone 11.4A-2);
- 1B diesel generator room (Fire Area 9.1-1);
- 2B diesel generator room (Fire Area 9.1-2);
- Division 12 Engineered safety feature switchgear room (Fire Zone 5.1-1);
- 1A and 2A SX pump room (Fire Area 11.1A); and
- CR on U1 diesel oil storage tank room foam suppression system blockage.

The inspectors verified that minor issues identified during the inspection were entered into the licensee's corrective action program by reviewing the documents listed in the Attachment.

b. Findings

Introduction

This inspection report identified one Unresolved Item (URI) pending completion of a review by a regional fire protection specialist and further onsite reviews of system code requirements. The URI is as follows:

- URI 05000456/2005003-01, Blockage in Foam Suppression System of Unit 1 Indoor Diesel-Generator Oil Storage Tank (DOST) Rooms

Description

The inspectors reviewed CR 347011, "Unit 1 DOST Foam System Piping Plugged with Foam Concentrate." On June 23, 2005, the licensee identified blockage in portions of the fire suppression foam delivery piping to both the 1A and 1B DOST rooms. This prevented foam concentrate from mixing with the water portion of the system, and therefore, eliminated the capability to inject foam into the rooms. The issue had originally been identified on July 11, 2000, after the licensee had discovered similar blockage in the Unit 2 DOST foam suppression piping. Although the Unit 2 piping was cleared, no corrective actions were performed on the Unit 1 piping until problems became self-evident on June 20, 2005, when a valve stroke-time surveillance failed. The failed surveillance prompted an evaluation into the conditions of the system, where the associated blockage was found.

The Unit 1 DOST rooms have heat detectors that alarm in the control room and rely on the foam system for fire suppression. The two rooms are also physically separated with fire barriers. The inspectors observed that the fire detection system was available, that the fire barriers were intact, and that the water portion of the foam suppression system was unaffected by the blockage and capable of being injected. However, it was unclear whether the water portion was itself sufficient to mitigate a design basis fire in either room. The inspectors also identified that the licensee's routine surveillance testing of the foam suppression system had not identified the piping blockage; however, it was unclear whether this meant that the testing was inadequate to demonstrate system operability per the National Fire Protection Association (NFPA) code requirements.

Further information was needed regarding the specific NFPA code requirements for DOST fire suppression and surveillance testing. Specifically, whether the availability of the water portion of the system was considered sufficient for fire mitigation and whether the surveillance testing was appropriate. The inspectors also required further discussions with the licensee staff to determine if the cause of the blockage had been adequately identified and to verify that it had not recurred in the Unit 2 piping. This issue is documented as URI 05000456/2005003-01, "Blockage in Foam Suppression System of Unit 1 Indoor DOST Rooms," pending completion of further reviews by the resident inspectors and by a regional fire protection specialist.

1R06 Flood Protection Measures (71111.06)

Internal Flooding Review

a. Inspection Scope

The inspectors evaluated the internal flooding controls during the planned replacement of the units 1B and 2B train SX suction valves. These valves were one of two isolation points in series that prevented water from the cooling lake from flooding the auxiliary building. This was an infrequently performed activity that required the licensee to implement several compensatory actions in order to mitigate the internal flooding risk. The work required that the licensee remove several flood mitigation barriers, institute compensatory flood watches, and install inflatable balloons in the SX suction piping upstream of the suction valves, to provide backup isolation.

The inspectors observed the compensatory actions instituted by the licensee during the planned duration of the work, including the installation of the inflatable balloons, and reviewed the licensee's procedures regarding auxiliary building flooding. Those documents reviewed during this inspection are listed in the Attachment. This review constituted one sample of this inspection requirement.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

Annual Review

a. Inspection Scope

The inspectors completed one sample by observing the thermal performance tests and reviewing the results for the Unit 0 and Unit 2 component cooling heat exchangers.

The inspectors observed that the testing methodology was consistent with applicable industry practice, that instrument uncertainties were properly accounted for, and that the test met the licensee's acceptance criteria.

The inspectors reviewed whether the testing was performed consistent with licensee procedures and with the guidance described in NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08)

.1 Piping Systems ISI

a. Inspection Scope

From April 18 through April 28, 2005, the inspectors conducted a review of the implementation of the licensee's ISI program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries for Unit 2. The inspectors selected the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI required examinations and Code components in order of risk priority as identified in Section 71111.08-03 of the inspection procedure, based upon the ISI activities available for review during the onsite inspection period.

The inspectors observed the following two types of nondestructive examination activities:

- ultrasonic examination (UT) of welds 2FW-02-17, 2FW-02-18 and 2FW 02-21.01 in the main feedwater system, to evaluate compliance with the ASME Code Section XI and Section V requirements and to verify that indications and defects (if present) were dispositioned in accordance with the ASME Code Section XI requirements; and
- bare metal visual examination of the pressurizer to evaluate compliance with licensee commitments to NRC Bulletin 2004-01 penetrations (report Section 4OA5.1).

The inspectors reviewed two Code VT-2 examinations from the previous outage with relevant indications identified in work orders (WOs) 00454104-01 and 99247705 to determine if the licensee's corrective actions and extent of condition reviews were in accordance with the ASME Code requirements.

The inspectors reviewed pressure boundary welds for Class 1 or 2 systems which were completed since the beginning of the previous refueling outage, to determine if the welding acceptance and preservice examinations (e.g., pressure testing, visual, dye penetrant, and weld procedure qualification tensile tests and bend tests) were performed in accordance with ASME Code Sections III, V, IX, and XI requirements. Specifically, the inspectors reviewed records of field welds associated with the disassembling and inspection of the reactor coolant pump 2A seal injection inlet check valve 2CV8368A.

The inspectors performed a review of ISI related problems that were identified by the licensee and entered into the corrective action program, conducted interviews with licensee staff and reviewed licensee corrective action records to determine if:

- the licensee had described the scope of the ISI related problems;
- the licensee had established an appropriate threshold for identifying issues;
- the licensee had evaluated industry generic issues related to ISI and pressure boundary integrity; and
- the licensee implemented appropriate corrective actions.

The inspectors performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment.

The reviews as discussed above counted as one inspection sample.

b. Findings

No findings of significance were identified.

.2 Pressurized Water Reactor (PWR) Vessel Head Penetration ISI

a. Inspection Scope

The inspectors did not perform a review of this procedure section (reduction in one inspection sample), because it is not required to be implemented until after completion of Temporary Instruction (TI) 2515/150, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles." Implementation of TI 2515/150 is described in Section 4OA5.2 of this report.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control (BACC) ISI

a. Inspection Scope

From April 18 through April 28, 2005, the inspectors reviewed the Unit 2 BACC inspection activities conducted pursuant to licensee commitments made in response to NRC Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary.

The inspectors reviewed the licensee records generated during the BACC walkdown of the reactor coolant and other borated systems to evaluate compliance with licensee BACC program requirements and 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requirements. In particular, the inspectors observed these examinations to determine if the licensee focused on locations where boric acid leaks can cause degradation of safety significant components and that degraded or non-conforming conditions were properly identified in the licensee’s corrective action system. The inspectors reviewed engineering evaluations performed for boric acid found on reactor coolant system piping and components to verify that the minimum design code required section thickness had been maintained for the affected component(s). Specifically, the inspectors reviewed:

- evaluation 285241 for component 2RY455B, “Pressurizer Spray Valve;”
- evaluation 288352 for component 2SI162, “Emergency Core Cooling System Lines 2SIK10A, 2SI05AB-8 Vent Valve;” and
- evaluation 287724 for component 2CV214A, “2CV06MA Line High Point Vent Valve.”

The inspectors reviewed licensee corrective actions implemented for evidence of boric acid leakage to confirm that they were consistent with requirements of Section XI of the ASME Code and 10 CFR Part 50, Appendix B, Criterion XVI. Specifically, the inspectors reviewed:

- CR 322632 for component 2PT-0150, “2D RCP No.1 Seal Wide Range Pressure Transmitter;” and
- CR 322688 for component 2RC025B, “2B Reactor Coolant System Loop Instrumentation Isolation Valve.”

The documents reviewed during this inspection are listed in the Attachment to this report. The reviews as discussed above counted as one inspection sample.

b. Findings

No findings of significance were identified.

.4 Steam Generator (SG) Tube ISI

a. Inspection Scope

From April 18 through May 6, 2005, the inspectors performed an on-site review of SG tube examination activities conducted pursuant to TS and the ASME Code Section XI requirements.

The NRC inspectors observed acquisition of eddy current (ET) data, interviewed ET data analysts, and reviewed documents related to the SG ISI program to determine if:

- in-situ SG tube pressure testing screening criteria and the methodologies used to derive these criteria were consistent with the Electric Power Research Institute (EPRI) TR-107620, “Steam Generator In Situ Pressure Test Guidelines;”
- the in-situ SG tube pressure testing screening criteria were properly applied in terms of SG tube selection based upon evaluation of the list of tubes with measured/sized flaws;
- the numbers and sizes of SG tube flaws/degradation identified was bound by the licensee’s previous outage operational assessment predictions;
- the SG tube ET examination scope and expansion criteria were sufficient to identify tube degradation based on site and industry operating experience by confirming that the ET scope completed was consistent with the licensee’s procedures, plant TS requirements and EPRI 1003138, “Pressurized Water Reactor Steam Generator Examination Guidelines,” Revision 6;
- the SG tube ET examination scope included tube areas which represent ET challenges such as the tubesheet regions, expansion transitions and support plates;
- the licensee identified new tube degradation mechanisms;
- the licensee implemented repair methods which were consistent with the repair processes allowed in the plant TS requirements;
- the licensee primary-to-secondary leakage (e.g., SG tube leakage) was below the detection threshold during the previous operating cycle;
- the licensee did an evaluation for unretrievable loose parts identified in the 1D SG;
- the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, “Performance Demonstration for Eddy Current Examination,” of EPRI 1003138, “Pressurized Water Reactor Steam Generator Examination Guidelines,” Revision 6; and
- the licensee identified deviations from ET data acquisition or analysis procedures.

The inspectors performed a review of SG ISI related problems that were identified by the licensee and entered into the corrective action program, conducted interviews with licensee staff and reviewed licensee corrective action records to determine if:

- the licensee had described the scope of the SG related problems;
- the licensee had established an appropriate threshold for identifying issues;

- the licensee had evaluated industry generic issues related to SG tube integrity; and
- the licensee implemented appropriate corrective actions.

The inspectors performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment.

The NRC inspectors concluded that the reviews discussed above did not count as a completed inspection sample as described in Section 71111.08-5 of the inspection procedure, but the sample was completed to the extent possible.

The specific activities which were not available for the NRC inspectors' review to complete the procedure sample and the basis for their unavailability is identified below.

- procedure 71111.08, Steps 02.04.a.3 and 02.04.a.4 associated with review of in-situ pressure testing and tube performance criteria were not available for review because none of the degraded SG tubes met the screening requirements for pressure testing;
- procedure 71111.08, Step 02.04.d associated with review of licensee activities for new SG tube degradation mechanisms was not available for review because no new tube degradation mechanisms were identified; and
- procedure 71111.08, Step 02.04.h associated with review of corrective actions for primary-to-secondary leakage greater than 3 gallons per day was not available for review because primary-to-secondary leakage was below the minimum detectable threshold during the previous operating cycle.

b. <u>Findings</u>

No findings of significance were identified.

1R11 <u>Licensed Operator Requalification Program</u> (71111.11)

<u>Quarterly Review of Testing/Training Activity</u>

a. <u>Inspection Scope</u>

The inspectors observed the operating crew performance during evaluated simulator out-of-the-box scenario, Braidwood Station Licensed Operator Requalification Simulator Scenario Number BR-22, "Respond to a Feedline Break Inside Containment and Miscellaneous Malfunctions," Revision 0.

The inspectors evaluated crew performance in the following areas:

- clarity and formality of communications;
- ability to take timely actions in the safe direction;
- prioritization, interpretation, and verification of alarms;
- procedure use;
- control board manipulations;

- oversight and direction from supervisors; and
- group dynamics.

Crew performance in these areas was compared to licensee management expectations and guidelines.

The inspectors verified that the crew completed the critical tasks listed in the simulator guide. The inspectors also compared simulator configurations with actual control board configurations. For any weaknesses identified, the inspectors observed the licensee evaluators to determine whether they also noted the issues and discussed them in the critique at the end of the session. This review constituted one sample of this inspection requirement.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

Routine Inspection

a. Inspection Scope

The inspectors reviewed the licensee's overall maintenance effectiveness for the selected system below. This evaluation consisted of the following specific activities:

- observing the conduct of planned and emergent maintenance activities where possible;
- reviewing selected CRs, open WOs, and control room log entries in order to identify system deficiencies;
- reviewing licensee system monitoring and trend reports;
- attending various meetings throughout the inspection period where the status of maintenance rule activities was discussed;
- a partial walkdown of the selected system; and
- interviews with the appropriate system engineer.

The inspectors also reviewed whether the licensee properly implemented Maintenance Rule, 10 CFR 50.65, for the system. Specifically, the inspectors determined whether:

- the system was scoped in accordance with 10 CFR 50.65;
- performance problems constituted maintenance rule functional failures;
- the system had been assigned the proper safety significance classification;
- the system was properly classified as (a)(1) or (a)(2); and
- the goals and corrective actions for the system were appropriate.

The above aspects were evaluated using the maintenance rule program and other documents listed in the Attachment. The inspectors also verified that the licensee was appropriately tracking reliability and/or unavailability for the systems.

The inspectors completed one sample in this inspection requirement by reviewing the following system:

- Unit 1 and 2 main steam.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's management of plant risk during emergent maintenance activities or during activities where more than one significant system or train was unavailable. The activities were chosen based on their potential impact on increasing the probability of an initiating event or impacting the operation of safety-significant equipment. The inspections were conducted to determine whether evaluation, planning, control, and performance of the work were done in a manner to reduce the risk and minimize the duration where practical, and that contingency plans were in place where appropriate.

The licensee's daily configuration risk assessments records, observations of operator turnover and plan-of-the-day meetings, and observations of work in progress, were used by the inspectors to verify that the equipment configurations were properly listed, that protected equipment were identified and were being controlled where appropriate, that work was being conducted properly, and that significant aspects of plant risk were being communicated to the necessary personnel.

In addition, the inspectors reviewed selected issues, listed in the Attachment, that the licensee encountered during the activities, to determine whether problems were being entered into the corrective action program with the appropriate characterization and significance.

The inspectors completed six samples by reviewing the following activities:

- Unit 1 risk mitigation with 0A fire pump, 2A circulating water forebay and 2B SX systems out-of-service;
- spent fuel pool cooling contingency plan for bus 244 outage and required equipment walkdown for bus 232X outage (1 sample);
- identification of foreign material in the emergency core cooling system reactor coolant system cold leg injection pathway from the 2B safety injection pump;
- potential Orange risk configuration during troubleshooting of Unit 2 pressurizer power operated relief valve;
- discovery of missed inservice inspections on Unit 1 and 2 post accident containment hydrogen monitoring system lines; and
- maintenance on the 1B emergency diesel generator.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

a. Inspection Scope

The inspectors completed one sample by observing the following event:

- response to Hi-2 level isolation of 27A feedwater heater on April 4, 2005.

The inspectors observed the control room response, interviewed plant operators and reviewed plant records including control room logs, operator turnovers, and CRs. The inspectors verified that the control room response was consistent with station procedures and determined whether identified discrepancies were captured in the corrective action program. Corrective action documents reviewed as part of this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors evaluated plant conditions and selected CRs for risk-significant components and systems in which operability issues were questioned. These conditions were evaluated to determine whether the operability of components was justified. The inspectors compared the operability and design criteria in the appropriate section of the UFSAR to the licensee's evaluations presented in the CRs and documents listed in the Attachment to verify that the components or systems were operable. The inspectors also conducted interviews with the appropriate licensee system engineers and conducted plant walkdowns, as necessary, to obtain further information regarding operability questions.

The inspectors completed five samples by reviewing the following operability evaluations and conditions:

- CR 323008, "Unit 2 Containment Emergency Hatch Local Leak Rate Test Leakage Greater Than Allowable Limit," dated April 9, 2005;
- CR 326376, "Audio Count Rate Speaker is Missing From Unit 2 Containment," dated April 19, 2005;
- CR 328095, "Crack in 2C Reactor Containment Fan Cooler Turning Vane," dated April 23, 2005, and CR 326978, "2B Reactor Containment Fan Cooler Turning Vane had Three Cracks," dated April 21, 2005 (one sample);

- foreign material in Units 1 and 2 emergency core cooling system piping; and
- selected CRs dealing with incorrect/potentially incorrect plant components being installed (one sample).

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

.1 Review of Selected Operator Workarounds

a. Inspection Scope

The inspectors conducted reviews of plant conditions and documents to determine whether there were any issues that should have been evaluated and tracked as an operator work-around. The inspectors attempted to find conditions that could increase the potential for personnel errors or that would require compensatory actions to operate equipment during transients or events. The inspectors used the guidance in station procedure OP-AA-102-103, "Operator Work-Around Program," Revision 1, to identify potential operator work-arounds.

The inspectors completed one sample by conducting the following review:

- compensatory actions during troubleshooting of the Unit 2 digital rod position indication system.

The inspectors determined whether these issues were entered into the licensee's Corrective Actions Program and whether corrective actions were being appropriately developed. Documents reviewed as part of this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Semiannual Review of Operator Workarounds

a. Inspection Scope

The inspectors completed a semi-annual review of the cumulative effects of operator workarounds. The inspectors verified that the workarounds did not have a significant effect on the reliability, availability, or the ability to correctly operate mitigating systems and that they would not significantly increase operator response time to transients and accidents. The inspectors also verified that the licensee had plans and schedules established to correct the conditions in a reasonable time. In addition to operator workarounds, the inspectors reviewed operability evaluations, operator challenges, and temporary modifications for cumulative effects. The inspectors reviewed the documents listed in the Attachment as part of this inspection. This review represented one inspection sample.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed the modification documents and engineering change packages associated with the following permanent plant modification for both units:

- BRW-S-2005-0077, "Revise C-9 Interlock Setpoint (Condenser Vacuum)."

In addition to reviewing engineering change documents, the inspectors interviewed technical staff to verify that the changes did not adversely impact TS and design basis requirements. The inspectors also verified that the change did not introduce any new system vulnerabilities and that the affected operating procedures were identified and necessary changes were made. This review was considered one sample of this inspection requirement.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed post-maintenance testing activities associated with important mitigating systems, barrier integrity, and support systems to ensure that the testing adequately demonstrated system operability and functional capability. The inspectors used the appropriate sections of the TS and UFSAR, as well as the WOs for the work performed, to evaluate the scope of the maintenance and to determine whether the post-maintenance testing was performed adequately, demonstrated that the maintenance was successful, and that operability was restored. The inspectors determined whether the testing met the frequency requirements; that the tests were conducted in accordance with the procedures, including establishing the proper plant conditions and prerequisites; that the test acceptance criteria was met; and that the results of the tests were properly reviewed and recorded. The activities were selected based on their importance in demonstrating mitigating systems capability and barrier integrity. The inspectors verified that minor issues identified during the inspection were entered into the licensee's corrective action program by reviewing the documents in the Attachment.

Seven samples were completed by observing post-maintenance testing of the following components:

- 2A emergency diesel generator emergency core cooling system sequencer test following relay timer and governor replacement;

- Unit 2 safety injection system full flow testing;
- 2B emergency diesel generator emergency core cooling system sequencer test following relay timer and governor replacement;
- 2B diesel driven auxiliary feedwater pump following planned maintenance;
- 1B heater drain pump following offsite motor repairs;
- Unit 2 digital rod position indication system following replacement of the pulse-to-analog converter; and
- 1B emergency diesel generator following planned maintenance.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors observed the licensee's performance during the eleventh Unit 2 refueling outage (A2R11) conducted between April 17 and May 7, 2005. This inspection constituted one sample of the inspection requirement.

Inspection activities included a review of the outage schedule, safe shutdown plan and administrative procedures governing the outage, periodic observations of equipment alignment risk control, maintenance activities, and control room activities. Specifically, the inspectors determined whether the licensee effectively managed elements of shutdown risk pertaining to reactivity control, decay heat removal, inventory control, electrical power control, containment integrity, and vital support systems.

The inspectors performed the following activities on a daily basis during the outage:

- attended control room operator and outage management turnover meetings to determine whether shutdown risk and plant status were well understood and communicated;
- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- observed the operability of reactor coolant system instrumentation and compared channels and trains against each other;
- performed walkdowns of the auxiliary and containment buildings to observe ongoing work activities; and
- reviewed selected issues that the licensee entered into its corrective action program to determine whether the problems were being entered with the appropriate characterization and significance, and that operability issues were resolved before startup.

During the routine walkdowns, the inspectors selectively checked to see that equipment configuration was appropriately maintained and that redundant equipment was available when maintenance was occurring on plant systems.

Additionally, the inspectors performed the following specific activities:

- reviewed the detailed outage schedule and risk control plans;
- observed the control room staff during portions of the plant shutdown and cooldown;
- reviewed the results of the licensee's initial containment Mode 3 walkdowns for evidence of reactor coolant leakage;
- observed portions of fuel offloading and onloading;
- observed several outage surveillance tests and post maintenance tests (documented in other sections of this report);
- observed control room response during periods of reduced reactor coolant inventory;
- performed a walkdown to observe containment cleanliness prior to Mode 4 entry; and
- observed the control room staff during reactor startup.

The inspectors checked to see that minor issues identified during the inspection were entered into the licensee's corrective action program. Documents reviewed during these inspection activities are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed surveillance testing activities associated with important mitigating systems, barrier integrity, and support systems to ensure that the testing adequately demonstrated system operability and functional capability. The inspectors used the appropriate sections of the TS and UFSAR, as well as the WOs for the work performed, to evaluate the scope of the maintenance and to determine whether the surveillance testing was performed adequately, demonstrated that the maintenance was successful, and that operability was restored. The inspectors determined whether the testing met the frequency requirements; that the tests were conducted in accordance with the procedures, including establishing the proper plant conditions and prerequisites; that the test acceptance criteria was met; and that the results of the tests were properly reviewed and recorded. The activities were selected based on their importance in demonstrating mitigating systems capability, barrier integrity and the initiating events cornerstone. The inspectors verified that minor issues identified during the inspection were entered into the licensee's corrective action program by reviewing the documents in the Attachment.

Six samples were completed by observing and evaluating the following surveillance tests:

- Unit 2 full flow test and equipment response time of auxiliary feedwater pumps;
- Unit 1 turbine driven feedwater pumps mechanical overspeed monthly test;

- 1A emergency diesel generator room fire dampers 18 month visual inspection;
- 2B auxiliary feedwater pump monthly start and run;
- 2B centrifugal charging pump; and
- 2A solid state protection system bi-monthly test.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following temporary modification:

- temporary weld repair of the 1A motor driven feedwater pump casing.

For each modification, the inspectors reviewed the associated design change paperwork, attended applicable prejob briefings and observed installation and/or removal. The inspectors also reviewed contingency plans, as applicable, for modifications supporting continued component operability or reliability. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's corrective action program. This review constituted one sample of this inspection requirement.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Review of Licensee Performance Indicators for the Occupational Exposure Cornerstone

a. Inspection Scope

The inspectors discussed performance indicators with the radiation protection (RP) staff and reviewed data from the licensee's corrective action program to determine if there were any performance indicators in the occupational exposure cornerstone that had not been reported and reviewed. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors identified three radiologically significant work areas within radiation areas, high radiation areas (HRAs), and potential airborne areas in the plant. Selected work packages and radiation work permits (RWP) were reviewed to determine if radiological controls including surveys, postings, air sampling data and barricades were acceptable. Work packages and RWPs included but were not limited to:

- RWP 10004529; A2R11 Reactor Head CRDM Volumetric Inspection; Revision 1;
- RWP 10004546; A2R11 Install & Remove SG Nozzle Covers; Revision 1; and
- RWP 10005140; A2R11 Manway & Diaphragm Removal, Installation & Bolt Cleaning; Revision 0.

This review represented one sample.

The identified radiologically significant work areas were walked down and surveyed to determine if the prescribed RWP, procedures, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers were properly located. This review represented one sample.

The inspectors reviewed selected RWPs and associated radiological controls used to access these and other radiologically significant areas, and evaluated the work control instructions and control barriers that were specified, in order to determine if the controls and requirements provided adequate worker protection. Site technical specification requirements for HRAs and locked high radiation areas were used as standards for the necessary barriers. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. The inspectors determined whether pre-job briefings emphasized to workers the actions required when their electronic dosimeters noticeably malfunctioned or alarmed. This review represented one sample.

The inspectors reviewed the licensee's job planning records and interviewed licensee representatives to determine if there were airborne radioactivity areas in the plant with a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent. Barrier integrity and engineering controls performance, such as high efficiency particulate filtration ventilation system operation and use of respiratory protection, were evaluated for worker protection. Work areas having a history of, or the potential for, airborne transuranic isotopes were reviewed to determine if the licensee had considered the potential for transuranic isotopes and had provided appropriate worker protection. This review represented one sample.

The adequacy of the licensee's internal dose assessment process for internal exposures greater than 50 millirem committed effective dose equivalent was evaluated to ascertain whether affected personnel were properly monitored utilizing calibrated equipment and that the data was analyzed and internal exposures were properly assessed in accordance with licensee procedures. This review represented one sample.

The inspectors examined the licensee’s physical and programmatic controls for highly activated or contaminated materials (nonfuel) stored within the spent fuel or other storage pools. This included discussions with cognizant licensee representatives. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee’s self-assessments, audits, and CRs related to the access control program to determine if identified problems were entered into the corrective action program for resolution. This review represented one sample.

Corrective action reports related to access controls and HRA radiological incidents (non-performance indicator occurrences identified by the licensee in HRAs less than 1 Rem/hr) were reviewed. Staff members were interviewed and corrective action documents were reviewed to determine if follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of Non-Cited Violations tracked in the corrective action system; and
- implementation/consideration of risk-significant operational experience feedback.

This review represented one sample.

The inspectors evaluated the licensee’s process for problem identification, characterization and prioritization in order to determine if problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies identified in the problem identification and resolution process, the inspectors determined whether the licensee’s self-assessment activities also identified and addressed these deficiencies. This review represented one sample.

The inspectors discussed performance indicators with the RP staff and reviewed data from the licensee's corrective action program to determine if there were any performance indicators for the occupational exposure cornerstone that had not been reported and reviewed. There were none. This review represented one sample.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors selected three jobs being performed in radiation areas, potential airborne radioactivity areas, and HRAs for observation of work activities that presented the greatest radiological risk to workers and included areas where radiological gradients were present. This involved work that was estimated to result in higher collective doses, and included SG and reactor head work, and other selected work areas.

The inspectors reviewed radiological job requirements including RWP and work procedure requirements, and attended as low as is reasonably achievable (ALARA) job briefings. Job performance was observed with respect to these requirements to ascertain whether radiological conditions in the work area were adequately communicated to workers through pre-job briefings and radiological condition postings. This review represented one sample.

The inspectors also evaluated the adequacy of radiological controls including required radiation, contamination and airborne surveys for system breaches and entry into HRAs. Radiation protection job coverage which included direct visual surveillance by RP technicians along with the remote monitoring and teledosimetry systems, and contamination control processes were reviewed to assess the effectiveness of worker protection from radiological exposure. This review represented one sample.

Work in HRAs having significant dose rate gradients was observed to assess the application of dosimetry to effectively monitor exposure to personnel and to evaluate the adequacy of licensee controls. The inspectors observed RP coverage of SG and vessel head work which required controlling worker locations based on radiation survey data and real time monitoring using teledosimetry in order to maintain personnel radiological exposure ALARA. This review represented one sample.

b. Findings

No findings of significance were identified.

.5 High Risk Significant, High Dose Rate, High Radiation Area, and Very High Radiation Area Controls

a. Inspection Scope

The inspectors reviewed the licensee's performance indicators for high risk HRAs and for all very high radiation areas (VHRAs) to determine if workers were adequately protected from radiological overexposure. Discussions were held with RP management concerning high dose rate/HRA and very high radiation area controls and procedures, including procedural changes that had occurred since the last inspection. This was done to determine whether any procedure modifications would have substantially reduced the effectiveness and level of worker protection. This review represented one sample.

The inspectors evaluated the controls (including Procedures RP-AA-460, "Controls For High And Very High Radiation Areas," Revision 7, and RP-AP-460, "Access To Reactor Incore Sump Area," Revision 1) that were in place for special areas that had the potential to become VHRAs during certain plant operations. Discussions were held with RP supervisors to determine how the required communications between the RP group and other involved groups would occur beforehand in order to allow corresponding timely actions to properly post and control the radiation hazards. This review represented one sample.

During plant walkdowns, the posting and locking of entrances to high dose rate HRAs and VHRAs were reviewed for adequacy. This review represented one sample.

b. Findings

No findings of significance were identified.

.6 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated RP work requirements. The inspectors also evaluated whether workers were aware of the significant radiological conditions in their workplace, the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present. This review represented one sample.

Radiological problem reports, which found that the cause of an event resulted from radiation worker errors, were reviewed to determine if there was an observable pattern traceable to a similar cause and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. This review represented one sample.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

The inspectors observed and evaluated RP technician performance with respect to RP work requirements. This was done to evaluate whether the technicians were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities. This review represented one sample.

Radiological problem reports, which found that the cause of an event was RP technician error, were reviewed to determine if there was an observable pattern traceable to a similar cause and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. This review represented one sample.

b. Findings

No findings of significance were identified.

2OS2 As Low As Is Reasonably Achievable Planning And Controls (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed site specific trends in collective exposures and source-term measurements. This review represented one sample.

Procedures associated with maintaining occupational exposures ALARA, and processes used to estimate and track work activity specific exposures were reviewed. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors compared the results achieved, including dose rate reductions and person-rem used, with the intended dose established in the licensee's ALARA planning for selected work activities. Reasons for inconsistencies between intended and actual work activity doses were evaluated to determine if differences were the result of radiation controls or job planning. This review represented one sample.

The integration of ALARA requirements into work procedures and RWP documents was evaluated to determine if the licensee's radiological job planning would reduce dose. This review represented one sample.

Shielding requests from the RP group were evaluated with respect to dose rate reduction and reduced worker exposure, along with engineering shielding responses follow-up. This review represented one sample.

The inspectors reviewed work activity planning to establish that there was consideration of the benefits of dose rate reduction activities such as shielding provided by water filled components and piping, job scheduling, along with shielding and scaffolding installation and removal activities. This review represented one sample.

The licensee's post-job (work activity) reviews were evaluated to determine if identified problems were entered into the licensee's corrective action program for resolution. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Job Site Inspections and ALARA Controls

a. Inspection Scope

Radiological exposures of individuals from selected work groups were reviewed to evaluate any significant exposure variations which could exist among workers and to determine whether significant exposure variations were the result of worker job skill differences or whether certain workers received higher doses because of poor ALARA work practices. This review represented one sample.

b. Findings

No findings of significance were identified.

.4 Source-Term Reduction and Control

a. Inspection Scope

The inspectors reviewed licensee records to determine the historical trends and current status of tracked plant source terms and determined that the licensee was making allowances and 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. This review represented one sample.

The inspectors verified that the licensee had developed an understanding of the plant source-term, which included knowledge of input mechanisms in order to reduce the source term. The licensee's source-term control strategy was evaluated. This included a cobalt reduction strategy and a shutdown chemistry plan. Other methods used by the licensee to control the source term, including component/system decontamination and the use of shielding, were evaluated. This review represented one sample.

b. Findings

No findings of significance were identified.

.5 Declared Pregnant Workers

a. Inspection Scope

The inspectors reviewed the licensee’s procedure and process for monitoring the radiological exposure of declared pregnant workers to determine if the controls complied with the requirements of 10 CFR 20.1208. There were no declared pregnant workers during this assessment period. This review represented one sample.

b. Findings

No findings of significance were identified.

.6 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee’s self-assessments, audits, and Special Reports 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 met the requirements of 10 CFR 20.1101(c). This review represented one sample.

The inspectors determined if identified problems were entered into the corrective action program for resolution, and that they had been properly characterized, prioritized, and resolved. This included dose significant post-job (work activity) reviews and post-outage ALARA report critiques of exposure performance. This review represented one sample.

Corrective action reports related to the ALARA program were reviewed and staff members were interviewed to determine if follow-up activities had been conducted in an effective and timely manner commensurate with their importance to safety and risk using the following criteria:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of Non-Cited Violations tracked in the corrective action system; and
- implementation/consideration of risk-significant operational experience feedback.

This review represented one sample.

The inspectors also determined that the licensee’s self-assessment program identified and addressed repetitive deficiencies and significant individual deficiencies that were identified in the licensee's problem identification and resolution process. This review represented one sample.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS1 Radioactive Gaseous And Liquid Effluent Treatment And Monitoring Systems (71122.01)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the most recent Radiological Effluent Release Reports for 2003, dated April 30, 2004; and for 2004, dated April 27, 2005, along with current effluent release data to determine if the program was implemented as described in the Radiological Environmental Technical Specifications/Offsite Dose Calculation Manual (RETS/ODCM), and the UFSAR. The effluent report was also evaluated to determine if there were any significant changes to the ODCM or to the radioactive waste system design and operation. There were no significant changes to the ODCM, and no significant modifications had been made to the radioactive waste system design and operation. There were no anomalous results in the effluent report.

The RETS/ODCM and UFSAR were reviewed to identify the effluent radiation monitoring systems and associated flow measurement devices. Licensee records including CRs, self-assessments, audits, and special reports were reviewed to determine if there were any radiological effluent performance indicator occurrences or any unanticipated offsite releases of radioactive material for follow-up. The UFSAR description of all radioactive waste systems was reviewed. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Onsite Inspection

a. Inspection Scope

The inspectors walked down the major accessible components of the gaseous and liquid release systems, including radiation and flow monitors, tanks, and vessels. This was done to observe current system configuration with respect to the description in the UFSAR, ongoing activities, and equipment material condition. This review represented one sample.

The inspectors reviewed system diagrams of the radioactive liquid waste processing and release systems to determine how liquid radwaste was processed, and observed the collection and analysis of a liquid radwaste sample to verify that appropriate treatment equipment was used and that radioactive liquid waste was processed in accordance with procedural requirements. Liquid effluent release packages including projected doses to the public were reviewed to determine if regulatory effluent release limits were exceeded. The inspectors reviewed system diagrams of the radioactive gaseous effluent processing and release systems to determine if appropriate treatment equipment was used and if the radioactive gaseous effluent was processed and released in accordance with RETS/ODCM requirements. Radioactive gaseous effluent release data including the projected doses to members of the public was evaluated to determine if regulatory effluent release limits were exceeded. This review represented one sample.

The inspectors reviewed the licensee’s process for making releases with inoperable effluent radiation monitors to determine if adequate compensatory sampling and analyses was performed and to determine if an adequate defense-in-depth was maintained against an unmonitored, unanticipated release of radioactive material to the environment. This included projected radiological doses to members of the public. There were no abnormal releases noted. This review represented one sample.

There had been no significant changes made to the ODCM or to the liquid and gaseous radioactive waste system design, procedures, or operation including effluent monitoring and release controls since the last inspection. The inspectors also reviewed the licensee’s offsite dose calculations and evaluated the increased dose values reported in the 2004 annual report that resulted from gaseous releases during the Fall 2004 refueling outage. This review included the root cause analysis for this increase and a review of the licensee’s verification of the offsite dose calculation software. This review represented one sample.

The inspectors reviewed a selection of monthly, quarterly, and annual dose calculations to ensure that the licensee properly calculated the offsite dose from radiological effluent releases and to determine if any annual RETS/ODCM (i.e., Appendix I to 10 CFR Part 50) values were exceeded. This review represented one sample.

The inspectors reviewed air cleaning system surveillance test results to determine if the system was operating within the licensee’s acceptance criteria. The inspectors reviewed surveillance test results for the vent flow rates and determined if the flow rates were consistent with UFSAR values. This review represented one sample.

The inspectors reviewed records of instrument calibrations performed since the last inspection for each point of discharge effluent radiation monitor and flow measurement device. The current effluent radiation monitor alarm set point values were reviewed for agreement with RETS/ODCM requirements. The inspectors also reviewed calibration records of radiation measurement (i.e., counting room) instrumentation associated with effluent monitoring and release activities. Quality control data for the radiation measurement instruments were evaluated to determine if the instrumentation was operating under statistical control and that any problems observed were addressed in a timely manner. This review represented one sample.

The inspectors reviewed the results of the interlaboratory comparison program to determine the adequacy of the quality of radioactive effluent sample analyses performed by the licensee. The inspectors reviewed the licensee's quality control evaluation of the interlaboratory comparison test results. In addition, the inspectors reviewed the results from the licensee's quality assurance audits to determine whether the licensee met the requirements of the RETS/ODCM. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed the licensee's self assessments, audits, and special reports related to the radioactive effluent treatment and monitoring program since the last inspection to determine if identified problems were entered into the corrective action program for resolution. The inspectors also determined whether the licensee's self-assessment program identified and addressed repetitive deficiencies or significant individual deficiencies that were identified in problem identification and resolution.

The inspectors also reviewed corrective action reports from the radioactive effluent treatment and monitoring program, interviewed staff and reviewed documents to determine if the following activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of non-cited violations tracked in the corrective action system; and
- implementation/consideration of risk significant operational experience feedback.

This review represented one sample.

b. Findings

No findings of significance were identified.

2PS3 Radiological Environmental Monitoring Program (REMP) And Radioactive Material Control Program (71122.03)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the most current Annual Environmental Monitoring Report dated May 11, 2005, and licensee assessment results to determine if the REMP was implemented as required by the RETS/ODCM. The inspectors reviewed the report for changes to the RETS/ODCM with respect to environmental monitoring and commitments in terms of sampling locations, monitoring and measurement frequencies, land use census, interlaboratory comparison program, and data analysis. The inspectors reviewed the ODCM for information regarding environmental monitoring locations and evaluated licensee self-assessments, audits, special reports, and interlaboratory comparison program results. The inspectors reviewed the UFSAR for information regarding the environmental monitoring program and meteorological monitoring instrumentation. The inspectors also reviewed the scope of the licensee's audit program to determine if it met the requirements of 10 CFR 20.1101(c). This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Onsite Inspection

a. Inspection Scope

The inspectors visited the eight air sampling stations and approximately 50 percent of the thermoluminescent dosimeter monitoring stations to determine whether they were located as described in the ODCM and to determine the equipment material condition. This review represented one sample.

The inspectors observed the collection and preparation of a variety of environmental samples including milk, drinking water, surface water, and air. The environmental sampling program was evaluated to determine if it was representative of the release pathways as specified in the ODCM and that sampling techniques were performed in accordance with station procedures. This review represented one sample.

The inspectors determined if the meteorological instruments were operable, calibrated, and maintained in accordance with guidance contained in the annual report, NRC Safety Guide 23, and licensee procedures. The inspectors determined if the meteorological data readout and recording instruments including computer interfaces and data loggers at the tower were operable; that readouts of wind speed, wind direction, delta temperature, and atmospheric stability measurements were available on the licensee's computer system, which was available in the control room; and that the system was operable. This review represented one sample.

The inspectors reviewed each event documented in the Annual Environmental Monitoring Report which involved missed samples, inoperable samplers, lost thermoluminescent dosimeters, or anomalous measurements for the cause and corrective actions. The licensee's assessment of the one positive sample result was reviewed including the effluent release data that indicated the likely source of the released material. This review represented one sample.

The inspectors reviewed the ODCM for significant changes resulting from land use census modifications, or sampling station changes made since the last inspection. There were none. This review represented one sample.

The inspectors reviewed the calibration and maintenance records for the eight air samplers. The inspectors also reviewed calibration records for radiation measurement (counting room) instrumentation that could be used for environmental sample analysis and was used for the free release of liquids or pourable solids from the radiologically restricted area. This included determining if the appropriate detection sensitivities would be achieved for counting samples, in that the instrumentation could achieve the RETS/ODCM required environmental lower levels of detection limits. The inspectors reviewed quality control data used to monitor radiation measurement instrument performance and actions that would be taken if indications of degrading detector performance were observed.

The licensee does not perform radio-chemical analyses of REMP samples. The inspectors reviewed a licensee audit of the vendor laboratory that analyzed these samples. Corrective actions for deficiencies identified in the audit were evaluated along with the vendor's interlaboratory comparison program to verify the adequacy of the vendor's analytical and quality assurance programs. This included a review of the licensee's evaluation of the data for bias and the overall effect on the REMP.

The inspectors also reviewed the results of the licensee's and the vendor laboratory's interlaboratory comparison programs, to evaluate the adequacy of radio-chemical analyses performed by these laboratories. The quality assurance organization's evaluation of the intercomparison program was examined, including corrective actions for deficiencies. The inspectors reviewed quality assurance audit results of the program to determine whether the licensee met the TS/ODCM requirements. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Unrestricted Release of Material from the Radiologically Restricted Area

a. Inspection Scope

The inspectors observed the access control location where the licensee monitored potentially contaminated material leaving the radiologically restricted area and inspected the methods used for control, survey, and release of material from this area. The inspectors observed the performance of personnel surveying and releasing material for unrestricted use to determine if the work was performed in accordance with plant procedures. This review represented one sample.

The inspectors determined if the radiation monitoring instrumentation was appropriate for the radiation types present and was calibrated with appropriate radiation sources that represented the expected isotopic mix. The inspectors reviewed the licensee's criteria for the survey and release of potentially contaminated material and determined if there was guidance on how to respond to an alarm indicating the presence of licensed radioactive material. The inspectors evaluated the licensee's equipment to determine if radiation detection sensitivities were consistent with the NRC guidance contained in IE Circular 81-07 and IE Information Notice 85-92 for surface contamination, and HPPOS-221 for volumetrically contaminated material. The inspectors determined if the licensee performed radiation surveys to detect radionuclides that decay via electron capture.

The inspectors reviewed the licensee's procedures and records to determine if the radiation detection instrumentation was used at its typical sensitivity level based on appropriate counting parameters such as counting times and background radiation levels. The inspectors determined if the licensee had established a "release limit" by altering the instrument's typical sensitivity through such methods as raising the energy discriminator level or by locating the instrument in a high radiation background area. This review represented one sample.

b. Findings

No findings of significance were identified.

.4 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, Licensee Event Reports, and special reports related to the radiological environmental monitoring program since the last REMP inspection to determine if identified problems were entered into the corrective action program for resolution. The inspectors also determined if the licensee's self-assessment program was capable of identifying and addressing repetitive deficiencies or significant individual deficiencies that were identified by the problem identification and resolution process.

The inspectors also reviewed corrective action reports from the REMP that affected environmental sampling and analysis, and meteorological monitoring instrumentation. Staff members were interviewed and documents were reviewed to determine if the following activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of Non-Cited Violations tracked in the corrective action system; and
- implementation/consideration of risk significant operational experience feedback.

This review represented one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstones: Occupational and Public Radiation Safety

Radiation Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensee's Performance Indicator (PI) submittals for the periods listed below. The inspectors used PI definitions and guidance contained in Revision 3 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the PI data. The following PIs were reviewed:

- Occupational Exposure Control Effectiveness: Units 1 and 2

  The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety, to determine if indicator related data was adequately assessed and reported during the previous four quarters. The inspectors compared the licensee's PI data with the condition report database, reviewed radiological restricted area exit electronic dosimetry transaction records, and conducted walkdowns of accessible locked high radiation area entrances to verify the adequacy of controls in place for these areas. Data collection and analysis methods for PIs were discussed with licensee representatives to determine if there were any unaccounted for occurrences in the Occupational Radiation Safety PI as defined in Revision 3 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline." This review represented one sample.

- Radiological Environmental Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences: Units 1 and 2

  The inspectors reviewed data associated with the RETS/ODCM PI to determine if the indicator was accurately assessed and reported. This review included the licensee's condition report database for the previous four quarters, to identify any potential occurrences such as unmonitored, uncontrolled or improperly calculated effluent releases that may have impacted offsite dose. The inspectors also selectively reviewed gaseous and liquid effluent release data and the results of associated offsite dose calculations and quarterly PI verification records generated over the previous four quarters. Data collection and analyses methods for PIs were discussed with licensee representatives to determine if the process was implemented consistent with industry guidance in Revision 3 of

Nuclear Energy Institute Document 99-02, “Regulatory Assessment Performance Indicator Guideline.” This review represented one sample.

b. Findings

No findings of significance were identified.

Cornerstones: Mitigating Systems and Barrier Integrity

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to determine whether they were being entered into the licensee’s corrective action program at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Minor issues entered into the licensee’s corrective action program as a result of the inspectors’ observations are generally denoted in the Attachment. These activities were part of normal inspection activities and were not considered separate samples.

b. Findings

No finding of significance were identified.

.2 Semiannual Review for Trends

a. Inspection Scope

The inspectors reviewed all CRs generated during the time period between October 1, 2004, through March 31, 2005, in an attempt to identify potential trends involving adverse human or equipment performance. This inspection was part of the requirements of Inspection Procedure 71152 for monitoring plant status but was not considered an inspection procedure sample. Documents reviewed which may have indicated previously unrecognized trends are listed in the Attachment. The inspectors verified that minor issues identified during this inspection were entered into the licensee’s corrective action program.

The screening was accomplished by grouping CRs into broad categories during daily screening. These groups included, but were not limited to, items involving the same issue, same equipment/components, or the same program. For the period of review, the inspectors also obtained lists of all completed or ongoing licensee common cause investigations, all CRs where the title indicated a trend or potential trend, all systems currently in the maintenance rule (a)(1) status, and the licensee’s most recent System

Health Indicator Program report. These documents were considered licensee-identified trends. The following items were eliminated from the scope of this inspection:

- CRs dealing with company policies, administrative issues, and other minor issues;
- CRs associated with established licensee trending programs/processes, such as the rework program, that were previously reviewed during the semi-annual trend evaluation discussed in Inspection Reports 05000456/457/2004004 and 05000456/457/2004008;
- single CRs with no repeat occurrences or common issues;
- CRs that discussed NRC-identified trends from previous inspection activities;
- CRs that discussed strictly programmatic problems, as the inspection specifically focused on human and equipment performance issues;
- CRs involving Security, Radiation Protection, ISI and Emergency Preparedness issues, that were reviewed by regional specialists during ongoing inspection activities;
- CRs that were duplicates of other CRs involving the same event or failure;
- CRs generated as a result of a special licensee initiative to specifically look for issues in a certain area; and
- CRs associated with a trend previously identified by the licensee.

The review of equipment issues was limited to the instrument and service air, essential and non-essential service water, auxiliary feedwater, pressurizer, fire protection, and lake cooling systems. These systems were selected based on their risk significance per the licensee's probabilistic risk assessment model. The remaining groups were screened for potential common cause issues and were considered potential trends. These potential trends were then provided to the licensee for discussion and additional followup.

b. Findings

The inspectors determined that licensee employees were writing CRs with a low threshold, that employees at all levels of the organization were writing CRs, and that CRs were written for all issues of significance. The largest group of CRs concerned industrial safety issues, however, the inspectors also noted a large number of CRs for employee identified equipment issues. Collectively, this provided one indication of a safety conscious work environment.

The licensee identified a number of trends. Each trend was documented in a CR and evaluated to determine if a common cause evaluation was necessary. The licensee-identified trends were identified by a combination of the work groups involved with the issues, department or station corrective action program coordinators, department managers, and the nuclear oversight group, indicating that multiple groups were looking for trends.

The inspectors did not identify any new trends or potential trends that had not been already identified and recorded by the licensee through CR's. In each case, the evaluation and corrective action or proposed corrective actions were evaluated by the inspectors and found to be adequate.

.3 Review of the Licensee Refueling Outage (A2R11) CRs for Operability Considerations (one annual sample)

a. Inspection Scope

The inspectors reviewed a sampling of CR's generated during the April 2005, Unit 2 refueling outage (A2R11) with specific emphasis on operability of the systems and/or components involved. The review focused specifically on eight CR's selected from a sample of 43, and a group related to problems with the spent fuel pool bridge crane. The selected CR's are listed in the Attachment. The CR's were reviewed specifically for operability (past, present and future) considerations in the documentation.

The inspectors reviewed the content of the CR's and evaluations against the requirements of the licensee's Corrective Action Program Procedure LS-AA-125, NRC Inspection Manual Part 9900 Technical Guidance, and 10 CFR 50 Appendix B.

This review constituted one sample of this inspection requirement.

b. Findings and Observations

There were no significant findings identified with respect to operability in the samples reviewed. In each case reviewed, the licensee had provided consideration for current and past operability or had given guidance for future operability.

4OA3 Event Followup (71153)

The inspectors completed one inspection sample in this area.

Licensee Event Report (LER) Review

(Closed) LER 05000457/2005-002-00: Braidwood Unit 2 Reactor Trip Due to Main Generator 'C' Phase Bushing Failure Due to Over Heating.

This event is discussed in Section 4OA3.3 of NRC Inspection Report 05000456/457/2005002. On March 28, 2005, Unit 2 tripped from 100 percent power due to a main turbine generator protective relay actuation when the generator "C" phase stator output bushing failed. The reactor trip was uncomplicated and all systems responded as designed. During the reactor trip response, the licensee evacuated personnel from the turbine building due to an apparent uncontrollable leak of flammable hydrogen gas that could affect plant operations. Per the emergency plan, the licensee subsequently declared a Notice of Unusual Event and made the appropriate local, state and NRC notifications. The Unusual Event was terminated after the licensee isolated hydrogen flow to the generator and subsequently detected no measurable quantity of hydrogen in the turbine building atmosphere. The Unit 2 generator was repaired and brought back on line on April 1, 2005.

The licensee captured the reactor trip in CR 318027 and initiated a prompt investigation to determine the cause of the bushing failure.

The investigation identified that the bushing failure was due to a sudden failure of a modified mechanical joint in the bushing's bottom flange. This bushing was rebuilt and modified by a vendor prior to installation during Braidwood's Unit 2 refueling outage in November 2003. The licensee determined that all other main generator bushings are original equipment and have not been modified beyond the initial design. The licensee performed a root cause investigation for this event and issued the LER.

This LER was reviewed by the inspectors and no findings of significance were identified. Therefore, this LER is considered closed.

4OA5 Other Activities

.1 Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (TI 2515/160)

a. Inspection Scope

On May 28, 2004, the NRC issued Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors." The purpose of this Bulletin was to:

(1) Advise PWR licensees that current methods of inspecting Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections may need to be supplemented with additional measures to detect and adequately characterize flaws due to Primary water stress corrosion cracking;

(2) Request PWR addressees to provide the NRC with the information related to the materials from which the pressurizer penetrations and steam space piping connections at their facilities were fabricated; and

(3) Request PWR licensees to provide the NRC with the information related to the inspections that have been and those that will be performed to ensure that degradation of Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections will be identified, adequately characterized, and repair. The objective of TI 2515/160, "Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors," was to support the NRC review of licensees' activities for inspecting pressurizer penetrations and steam space piping connections made from Alloy 82/182/600 materials and to determine whether the inspections of these components are implemented in accordance with the licensee responses to Bulletin 2004-01. In response to Bulletin 2004-01, the licensee committed to perform a bare metal visual inspection of 100 percent of the five susceptible Inconel pressurizer penetrations in the upper pressurizer head using a VT-2 qualified examiner. On March 3, 2005, the inspectors observed the licensee performing this inspection and performed a review, in accordance with a TI 2515/160, of the licensee's controls and personnel used for pressurizer penetration nozzles and steam space piping connections examinations to confirm that the licensee met commitments associated with Bulletin 2004-01.

The results of the inspectors' review included documenting observations and conclusions in response to the questions identified in TI 2515/160.

b. Observations

Summary: Based upon a bare metal visual examination of the pressurizer, the licensee did not identify any indications of boric acid leaks from pressure retaining components in the pressurizer system.

Evaluation of Inspection Requirements

In accordance with the requirements of TI 2515/160, inspectors evaluated and answered the following questions:

1. For each of the examination methods used during the outage, was the examination performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

   Yes. The licensee conducted a direct visual examination of the bare metal surface of the upper pressurizer head heater penetration nozzles with a knowledgeable staff member certified to Level III as a VT-2 examiner in accordance with procedure TQ-AA-122, "Qualification and Certification of Boiler and Pressure Vessel Code Nondestructive Personnel." This qualification and certification procedure referenced the industry standards SNT-TC-1A, "Personnel Qualification and Certification in Nondestructive Testing," and ANSI/ANST CP-189, "Standard for Qualification and Certification of Nondestructive Testing Personnel."

2. For each of the examination methods used during the outage, was the examination performed in accordance with demonstrated procedures?

   Yes. The inspectors observed the licensee inspector performing the bare metal inspection of the pressurizer nozzles in accordance with procedure ER-AA-335-015, "VT-2 Visual Examination." The WO specified performing a VT-2 examination of the five pressurizer nozzles as described in the licensee's response to Bulletin 2004-01. The licensee's examiner used a flashlight for illumination during this inspection and photographed each penetration nozzle.

3. Able to identify, disposition, and resolve deficiencies?

   Yes. The inspectors concluded that the licensee's direct visual examinations were capable of detecting leakage from cracking in pressurizer penetrations if it had existed. This conclusion was based upon the inspectors direct observations of pressurizer penetration locations which were free of debris or deposits that could mask evidence of leakage in the areas examined.

4. Capable of identifying the leakage in pressurizer penetration nozzle or steam space piping components, as discussed in NRC Bulletin 2004-01?

Yes. The inspectors' basis is discussed in the answer to question 3 above.

5. What was the physical condition of the penetration nozzle and steam space piping components in the pressurizer system (e.g., debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

   The upper pressurizer head Inconel penetrations included three safety relief valve penetration nozzles, a power operated relief valve nozzle, and a spray line penetration nozzle. The inspectors observed that the canned metal reflective insulation had been removed from the pressurizer at these penetration locations to allow a bare metal visual examination. The inspectors performed a direct visual inspection for these pressurizer penetrations. Based on this examination, the area examined was clean and free of debris or deposits or other obstructions which could mask evidence of leakage.

6. How was the visual inspection conducted (e.g., with video camera or direct visual by the examination personnel)?

   The licensee conducted a direct bare metal visual examination of these pressurizer penetrations.

7. How complete was the coverage (e.g., 360 degrees around the circumference of all the nozzles)?

   The licensee performed a bare metal inspection of the five steam space piping connections/nozzles which included 360 degrees around the circumference of each penetration nozzle.

8. Could small boron deposits, as described in the Bulletin 2004-01, be identified and characterized?

   Yes. The inspectors determined through direct observation of the licensee's efforts that the licensee staff were capable of detecting pressurizer nozzle leakage, if any had existed. Because the licensee did not identify any deposits indicative of leakage in the areas examined, the inspectors could not assess the licensee's plans to characterize leakage on pressurizer components.

9. What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

   The licensee did not identify any material deficiencies that required repair.

10. What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?

    The licensee did not identify any impediments to an effective examination. All of the insulation had been removed around the nozzles to allow a direct visual examination of the bare metal for 360 degrees around the circumference of each penetration nozzle.

11. If volumetric or surface examination techniques were used for the augmented inspection examinations, what process did the licensee use to evaluate and dispose any indications that may have been detected as a result of the examinations?

    Not applicable. The licensee did not perform augmented volumetric or surface examinations.

12. Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components in the pressurizer system?

    Not applicable. The licensee did not identify any indications of boric acid leaks from pressure retaining components in the pressurizer system.

c. Findings

No findings of significance were identified.

.2 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (TI 2515/150)

a. Inspection Scope

On February 11, 2003, the NRC issued Order EA-03-009 (ADAMS Accession Number ML030410402). This order required examination of the reactor pressure vessel head and associated vessel head penetration (VHP) nozzles to detect Primary water stress corrosion cracking of VHP nozzles and corrosion of the vessel head. The purpose of TI 2515/150, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles,” was to implement an NRC review of the licensee's head and VHP nozzle inspection activities required by NRC Order EA-03-009. The inspectors performed a review in accordance with TI-2515/150 of the licensee’s procedures, equipment, and personnel used for examinations of the reactor vessel closure head (RVCH) and VHP nozzles to confirm that the licensee met requirements of NRC Order EA-03-009 (as revised by NRC letter dated February 20, 2004). The results of the inspectors’ review included documentation of observations in response to the questions identified in TI 2515/150.

From April 18, 2005 through April 25, 2005, the inspectors performed a review of the licensee’s RVCH inspection activities completed in response to NRC Order EA-03-009. This review included:

- observation of the licensee personnel conducting automated UT of five VHP nozzle locations and the vent line penetration from the on-site data acquisition trailer;
- interviews with nondestructive examination personnel performing non-destructive examinations of the RVCH and VHP nozzles from an on-site trailer;
- certification records of nondestructive examination personnel performing examinations of the RVCH and VHP nozzles;

- UT and ET examination procedures used for examinations of the RVCH and VHP nozzles;
- procedures used for identification and resolution of boric acid leakage from systems and components above the vessel head;
- the licensee's procedures and corrective actions implemented for boric acid leakage; and
- UT and ET examination records for the RVCH and VHP nozzles.

The inspectors conducted these reviews to confirm that the licensee performed the vessel head examinations in accordance with requirements of NRC Order EA-03-009, using procedures, equipment, and personnel qualified for the detection of Primary water stress corrosion cracking in vessel VHP nozzles and detection of vessel head wastage.

From April 25 through April 28, 2005, the inspectors reviewed the licensee's VHP nozzle susceptibility ranking calculation to:

- verify that appropriate plant-specific information was used as input;
- confirm the basis for the head temperature used by licensee; and
- determine if previous VHP cracks had been identified, and if so, documented in the susceptibility ranking calculation.

The documents reviewed by the inspectors in conducting this inspection are listed in the Attachment to this report.

b. Observations

Summary: As of the end of the last refueling outage, the Braidwood Unit 2 vessel head was at 1.7 effective degradation years (EDY), which is in the low susceptibility ranking category as described in NRC Order EA-03-009. To meet the inspection requirements of Order EA-03-009, the licensee completed automated UT and ET examinations for each of the 78 VHP nozzles and head vent line penetration nozzles. The licensee identified 14 vessel head penetrations with minor limitations in the volumetric examination scope required by Order EA-03-009. The licensee intended to request relaxation from the Order to accept these limitations after plant restart.

Overall, the inspectors concluded that the licensee had completed an examination of the reactor vessel head which was consistent with the requirements of NRC's Order EA-03-009 (with the exception of needed relaxation noted above). The inspectors documented conclusions in response to 11 specific questions related to the quality of personnel, procedures, and equipment used to perform the vessel head examination. For some of the questions in this temporary instruction, the inspectors could not independently confirm the ability of some of the nondestructive examination techniques to detect Primary water stress corrosion cracking. This condition reflected a lack of industry or vendor "qualified" techniques and did not represent a deviation from NRC Order EA-03-009, which did not specify qualification or demonstration standards for the nondestructive examination techniques used. Additionally, the inability to identify Primary water stress corrosion cracking within the J-groove weld is consistent with the requirements of Order EA-03-009, which does not require examination of the J-groove welds when UT of the nozzle base material has been completed.

Evaluation of Inspection Requirements

In accordance with the reporting requirements contained within TI 2515/150, Revision 3, the inspectors evaluated and answered the following questions:

a. For each of the examination methods used during the outage, was the examination:

1. Performed by qualified and knowledgeable personnel?

Yes. The licensee's vendor personnel that performed the automated UT and ET examinations were certified to level I, II, or III in UT examination in accordance with vendor Procedures WDP-9.2, "Qualification and Certification of Personnel in Nondestructive Examination;" GBRA 009 227 F, "Written Practice Nondestructive Testing Education, Training, Examination of Nondestructive Testing Personnel;" SSI-A-005, "Qualification and Certification of Nondestructive Examination Personnel;" and ANATEC-08, "Certification of Nondestructive Personnel."

2. Performed in accordance with demonstrated procedures?

Yes. The licensee's vendor performed automated UT and ET of VHP nozzles in accordance with Procedure WDI-UT-010, "Intraspect Ultrasonic Procedure for Inspection of Reactor Vessel Head Penetrations, Time of Flight Ultrasonic, Longitudinal Wave and Shear Wave," Revision 10. The vendor performed these examinations from the inside nozzle surface using probes which contained UT and ET equipment configurations which were consistent with those used during vendor mockup testing. The licensee's vendor had demonstrated an earlier version of this procedure on mockup VHP nozzles which contained cracks or simulated cracks as documented in EPRI MRP-89, "Materials Reliability Program Demonstrations of Vendor Equipment and Procedures for the Inspection of Control Rod Drive Mechanism Head Penetrations." The inspectors compared Revision 10 of Procedure WDI-UT-010 to Revision 3 which had been demonstrated as documented in EPRI MRP-89, to ensure that any equipment configuration changes did not affect flaw detection capability.

3. Able to identify, disposition, and resolve deficiencies and capable of identifying the Primary water stress corrosion cracking and/or head corrosion phenomena described in Order EA-03-009?

Automated UT/ET of VHP Nozzles Equipped with a Thermal Sleeve

Yes. The licensee's vendor examined the 55 sleeved control rod drive VHP nozzle base metal using a "Trinity Blade Probe" from the inside surface of the nozzles. The Trinity Blade Probe contained a time-of-flight-diffraction UT transducer, a zero degree UT transducer, and an ET coil designed to optimize detection of both circumferential and axial oriented flaws. The UT portion of this probe was also configured to detect leakage paths in the shrink fit region between the VHP nozzle tube and the reactor vessel head material. The licensee's vendor had detected Primary water stress corrosion cracking in VHP nozzles at Beaver Valley Unit 1 as documented in PVP2004-2555, "Advanced Nondestructive Examination Technologies for Alloy 600 Components," using this examination technique. Therefore, the inspectors concluded that this examination would have been effective for detection of Primary water stress corrosion cracking in the Byron Unit 1 VHPs.

Automated UT/ET of VHP Nozzles without a Thermal Sleeve

Yes. The licensee's vendor examined the 23 unsleeved control rod drive VHP nozzle base metal using a rotating probe from the inside surface. This probe contained time-of-flight-diffraction UT transducer pairs, zero degree UT transducers, and ET coils designed to optimize detection of both circumferential and axial oriented flaws. The UT portion of this probe was also configured to detect leakage paths in the shrink fit region between the VHP nozzle tube and the reactor vessel head material. The licensee's vendor had detected Primary water stress corrosion cracking in VHP nozzles at Beaver Valley Unit 1 as documented in PVP2004-2555, "Advanced Nondestructive Examination Technologies for Alloy 600 Components," using this examination technique. Therefore, the inspectors concluded that this examination would have been effective for detection of Primary water stress corrosion cracking in the Byron Unit 1 VHPs.

Vent Line Penetration ET

Unknown. The licensee's vendor used probes containing an array of ET coils to examine the inside of the head vent line and vent line VHP nozzle J-groove weld. However, the ET technique used had not been demonstrated for detection on Primary water stress corrosion cracking type flaws. Therefore, the inspectors could not independently confirm that this examination would have been effective at detection of Primary water stress corrosion cracking.

VHP Nozzle J-Groove Welds

No. The licensee's vendor examinations of the VHP nozzle base material were not designed to detect Primary water stress corrosion cracking contained entirely within the VHP nozzle

J-groove welds. Therefore, the inspectors concluded that these examinations would not be effective at identification of Primary water stress corrosion cracking flaws located in this region.

b. What was the physical condition of the reactor vessel head (e.g., debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

Not applicable. The licensee did not perform a bare metal visual examination during this outage. Additionally, during the boric acid walkdown at the beginning of the refueling outage, the licensee did not identify any indication of boric acid leakage from sources above the vessel head. Because no potential for boric acid deposits on the head were identified, the inspectors did not observe the physical condition of the vessel head.

c. Could small boron deposits, as described in the Bulletin 01-01, be identified and characterized?

Not applicable. The licensee performed a volumetric examination of the reactor from under the vessel head during the refueling outage and did not perform a bare metal visual examination as discussed above.

d. What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

None.

e. What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?

The licensee identified physical limitations (due to RVCH and VHP nozzle design configurations) to completing the extent of the examination coverage required by NRC Order EA-03-009. Specifically, the licensee could not meet the NRC Order EA-03-009, Requirement IV.C.(5)(i) to perform ultrasonic testing to at least one inch below the lowest point at the toe of the J-groove weld for fourteen VHP nozzles. The licensee staff stated that they intended to request relaxation from the NRC Order EA-03-009 requirements for these VHP nozzles.

f. What was the basis for the temperatures used in the susceptibility ranking calculation, were they plant-specific measurements, generic calculations, (e.g., thermal hydraulic modeling, instrument uncertainties), etc.?

NRC Order EA-03-009 required licensee's to calculate the susceptibility category of each reactor head to Primary water stress corrosion cracking-related degradation. The susceptibility category in EDY establishes the basis for the licensee to perform appropriate head inspections during each refueling outage. The licensee documented the Unit 2 reactor pressure vessel head EDY in calculation in document ECR-359165. In this calculation, the licensee used the formula required by NRC Order EA-03-009 and determined the EDY for each operating cycle. The licensee determined that the current EDY for the Braidwood Unit 2 reactor pressure vessel head as of May 1, 2004, is 1.7 EDY. This value placed the Unit 2 reactor pressure vessel head in the low susceptibility category.

NRC Order EA-03-009 also required the licensee to have used best estimate values in determining the susceptibility category for the vessel head. The inspectors reviewed DIT-BRW-2003-0013, which documents the effective full power operating years and the WO 00582805, which reviews Unit 2 Effective Full Power Years and determines the impact on pressure/temperature and low temperature over pressure protection curves. Based on this review, the inspector concluded that the licensee had used applicable plant specific information (e.g., best estimate values) in determining the EDY value.

g. During non-visual examinations, was the disposition of indications consistent with the guidance provided in Appendix D of this TI? If not, was a more restrictive flaw evaluation guidance used?

Unknown. The licensee did not identify any indications for which they had applied a flaw evaluation.

The inspectors reviewed the licensee's summary report which documented the results of the UT and ET examinations, as well as a sampling of the data records for the UT and ET of VHP nozzles.

For VHP penetrations 8 and 75, the licensee identified a small surface scratch on the ID of the penetration. These scratches were dispositioned by the licensee as "NDD" (no detectable degradation). However, because this condition could increase the susceptibility of the nozzles to Primary water stress corrosion cracking (e.g., reduce the initiation time for the onset of Primary water stress corrosion cracking), the licensee decided to evaluate this information and entered the condition into their corrective action system (CR 332753). This corrective action document was similar in nature to a corrective action document generated for Byron 1 during their most recent refueling outage (CR 313173). During that plant's outage, similar surface scratches were also discovered. Condition Report 332753 indicated that a corrective action for the conditions at both plants would be to have Westinghouse perform an evaluation of these conditions.

This issue was not an immediate operability concern because the growth of structurally limiting Primary water stress corrosion cracking would require a substantive period of plant operation. Therefore, the inspectors judged that the licensee had sufficient time to perform appropriate evaluations and followup inspections as required to ensure the integrity of these nozzles.

h. Did procedures exist to identify potential boric acid leaks from pressure-retaining components above the vessel head?

Yes. Procedure ER-AP-331-1001, "Boric Acid Corrosion Control Inspection Locations, Implementation and Inspection Guidelines," contained general walkdown inspection requirements. This procedure required BACC inspections after plant shutdown during each scheduled refueling outage by VT-2 examiners. The licensee did not identify any boric acid leaks from pressure-retaining components above the vessel head during this inspection.

i. Did the licensee perform appropriate follow-on examinations for boric acid leaks from pressure retaining components above the vessel head?

Not applicable. The licensee did not identify any boric acid leaks from pressure.

c. Findings

No findings of significance were identified.

.3 Operational Readiness of Offsite Power (TI 2515/163)

a. Inspection Scope

The objective of TI 2515/163, "Operational Readiness of Offsite Power," was to confirm, through inspections and interviews, the operational readiness of offsite power (OSP) systems in accordance with NRC requirements. The results of the inspectors' review included documenting observations and conclusions in response to the questions identified in TI 2515/163.

b. Observations

Summary: The licensee meets NRC requirements for managing the operational readiness of OSP systems.

Evaluation of Inspection Requirements

In accordance with the requirements of TI 2515/163, inspectors evaluated licensee procedures against the attributes discussed below.

The operating procedures that the control room operator uses to assure the operability of the OSP have the following attributes:

1. Identify the required control room operator actions to take when notified by the transmission system operator (TSO) that post-trip voltage of the OSP at the Nuclear power plant will not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply.

2. Identify the compensatory actions the control room operator is required to perform if the TSO is not able to predict the post-trip voltage at the nuclear power plant for the current grid conditions.

3. Identify the notifications required by 10 CFR 50.72 for an inoperable OSP system when the nuclear station is either informed by its TSO or when an actual degraded voltage condition is identified.

The procedures to ensure compliance with 10 CFR 50.65(a)(4) have the following attributes:

1. Direct the plant staff to perform grid reliability evaluations as part of the required maintenance risk assessment before taking a risk-significant piece of equipment out-of-service to do maintenance activities.

2. Direct the plant staff to ensure that the current status of the OSP system has been included in the risk management actions and compensatory actions to

reduce the risk when performing risk-significant maintenance activities or when LOOP or SBO mitigating equipment are taken out-of-service.

3. Direct the control room staff to address degrading grid conditions that may emerge during a maintenance activity.

4. Direct the plant staff to notify the TSO of risk changes that emerge during ongoing maintenance at the nuclear power plant.

The procedures to ensure compliance with 10 CFR 50.63 have the following attribute:

Direct the control room operators on the steps to be taken to try to recover OSP within the SBO coping time.

c. Findings

The information gathered during this TI was forwarded to NRR for further analysis.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. K. Polson and other members of licensee management at the conclusion of the inspection on July 7, 2005. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exit meetings were conducted for:

- The access control to radiologically significant areas program and the ALARA planning and controls program with Mr. K. Polson on April 28, 2005;
- Inservice Inspection (via telecon) on May 17, 2005;
- Inservice Inspection (Procedure 71111.08), TI 2515/150, and TI 2515/160, with Mr. K. Polson on May 18, 2005; and
- The radioactive gaseous and liquid effluent treatment and monitoring systems, and the radiological environmental monitoring program and radioactive material control programs and performance indicator verifications for occupational exposure control effectiveness, and RETS/ODCM radiological effluents, with Mr. K. Polson on May 26, 2005.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
K. Polson, Site Vice President
G. Boerschig Plant Manager
D. Ambler, Regulatory Assurance Manager
S. Butler, Licensing Engineer
B. Casey, ISI Coordinator
G. Dudek, Operations Director
C. Dunn, Site Training Director
T. Green, Braidwood Nondestructive Level III Engineer
G. Heisterman, Mechanical Maintenance Manager
T. Johnson, Reactor Vessel Project Manager
J. Kuczynski, Chemistry Manager
R. Leasure, Radiation Protection Manager
F. Lentine, Design Engineering Manager
J. Moser, Radiation Protection Manager
R. Rahrig, Operations Support Manager
M. Sears, Steam Generator Program Manager
M. Smith, Engineering Director
P. Summers, Nuclear Oversight Manager
E. Wrigley, Maintenance Director

Nuclear Regulatory Commission
G. Wilson, Acting Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000456/2005003-01	URI	Blockage in Foam Suppression System of Unit 1 Indoor Diesel-Generator Oil Storage Tank Rooms (Section 1R05)

Closed

05000457/2005-002-00	LER	Braidwood Unit 2 Reactor Trip Due to Main Generator ‘C; Phase Bushing Failure Due to Over Heating (Section 4OA3)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R01 Adverse Weather Protection

CR 342274; Elevated Main Steam Isolation Valve Temperatures; June 8, 2005
CR 342649; Main Steam Isolation Valve Rooms Get Hot and Temperature Fans Are Required; June 9, 2005
BwOP MS-5; Main Steam Isolation Valve Accumulator Operability Check; Revision 23
0BwOS XHT-A1; Unit Common High Temperature Equipment Protection Surveillance; Revision 8
WO 698098 01; High Temperature Equipment Protection; Marcy 10, 2005

1R04 Equipment Alignment

BwOP DG-1; Diesel Generator Alignment to Standby Condition; Revision 24
BwOP DG-E1; Electrical Lineup - Unit 1 1A Diesel Generator; Revision 6
BwOP DG-M1; Operating Mechanical Lineup Unit 1 1A D/G; Revision 14
BwOP MS-5; MSIV Accumulator Operability Check; Revision 23
BwOP VC-E1; Electrical Lineup - Unit 0 Operating; Revision 3E2
BwOP VC-E2; Electrical Lineup - Unit 0 Control Room Heating Ventilation and Air Conditioning; Revision 5
BwOP VC-M1; Operating Mechanical Lineup Unit 0 Control Room Heating Ventilation and Air Conditioning; Revision 5
0BwOS XHT-A1; Unit Common High Temperature Equipment Protection Surveillance; Revision 8
CR 342274; Elevated MSIV Temperatures; June 8, 2005
CR 3442649; MSIV Rooms Get Hot and Temperature Fans are Required; June 9, 2005
WO 698098; High Temperature Equipment Protection; March 10, 2005

1R05 Fire Protection

BwAP 1110-1; Fire Protection Program System Requirements; Revision 22
BwAP 1110-1A3; GOCAR Required Compensatory Measures Action Response Fire Protection Water Suppression Systems; Revision 5
BwMS FP-A6; Hard Rubber Fire Hose Hydrostatic Test Annual Surveillance; Revision 0
0BwOS FP.6.1.Q-1; Fire Hose Station Inspection Surveillance; Revision 7
Surveillance History for 0Bw0SFP.6.Q-1; June 15, 2005
0BwOS FP.6.1.F-3; Fire Hose Replacement 5 Year Surveillance (elevation 401 and below); Revision 4
Surveillance History for 0BwOS FP.6.1.F-3; June 15, 2005;
0BwOS FP.6.1.F-4; Fire Hose Replacement (5 Year) Surveillance (elevation 426 and above); Revision 5

CR 327327; NOS Missed Opportunity on Temporary Seal Installation; April 8, 2005
CR 327935; Fire Seal at Penetration SO362095 Degraded; April 19, 2005
CR 347011; U1 DOST Foam System Piping Plugged with Foam concentrate; June 23, 2005
EPN D-246; Unit 2 Plant Barrier Impairment Permit No. 8398; Door
EPN D-254; Unit 2 Plant Barrier Impairment Permit No. 8402; Door
1S-41; Braidwood Station Pre-fire Plan for Unit 1 Diesel Driven Auxiliary Feedwater Pump Room; March25, 2005
2S-41; Braidwood Station Pre-fire Plan for Unit 2 Diesel Driven Auxiliary Feedwater Pump Room; March25, 2005
1D-71; Braidwood Station Pre-fire Plan for 1B Diesel Generator Room; March25, 2005
2D-71; Braidwood Station Pre-fire Plan for 2B Diesel Generator Room; March25, 2005
1D-77; Braidwood Station Pre-fire Plan for Division 12 [Engineered Safety Feature] ESF Switchgear Room; March25, 2005
1S-27; Braidwood Station Pre-Fire Plan for Diesel Oil Tank Room 1B - Elevation 383'-0"
1S-28; Braidwood Station Pre-Fire Plan for Diesel Oil Tank Room 1A - Elevation 383'-0"
Byron/Braidwood Stations Fire Protection Report; Amendment 21; Sections:

2.3.5.1 Division 12 ESF Switchgear Room (Fire Area 5.1-1)
2.3.9.1 Diesel Generator Room 1B (Fire Area 9.1-1);
2.3.9.2 Diesel Generator Room 2B (Fire Area 9.1-2);
2..3.11.31 Unit 1 Auxiliary Feedwater Diesel Driven Pump Room (Fire Zone 11.4A-1);
2..3.1.32 Unit 2 Auxiliary Feedwater Diesel Driven Pump Room (Fire Zone 11.4A-2);
2.4.2.31 Division 12 ESF Switchgear Room (Fire Zone 5.1-1)
2.4.2.57 Diesel Generator 1B Room (Fire Zone 9.1-1)
2.4.2.58 Diesel Generator 2B Room (Fire Zone 9.1-2)
2.4.2.99 Unit 1 Auxiliary Feedwater Pump 1B Room (Fire Zone 11.4A-1);
2.4.2.100 Unit 2 Auxiliary Feedwater Pump 2B Room (Fire Zone 11.4A-2);

WO 763341; Hand Portable Fire Extinguisher Inspection Turbine Bld; March 8, 2005
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Surveillance History for BwMS FP-A6; June 15, 2005
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Figure 2.3-10; Mezzanine Floor Plan EL. 426'-0"; Sheets 1- Amendment 11; Sheet 2- Amendment 12; Sheet 3- Amendment 18; Sheet 4- Amendment 19;
Figure 2.3-12; Grade Floor EL. 401'-0"; Sheet 1-Amendment 15; Sheet 2- Amendment 12; Sheet 3-Amendment15; Sheet 4-Amendment 19;
Figure 3.3-13; Plan At EL. 383'-0'; Sheet 1-Amendment 18; Sheet 2-Amendment 18

<u>1R06</u> <u>Flood Protection Measures</u>

0BwOA PRI-8; Auxiliary Building Flooding Unit 0; Revision 2
Project Plan 1/2SX001B Essential Service Water (SX) Valve Replacements A2R11; Revision 1
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1R07 Heat Sink Performance

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1R08 Inservice Inspection Activities (71111.08)

Boric Acid Corrosion Control Program Engineering Evaluations

Evaluation No. 287724 for Component 2CV214A; Leakage Found at 2CV06MA Let Down Orifice High Point Vent Valve; January 12, 2005
Evaluation No. 288352 for Component 2SI162; Leakage Found in ECCS Lines 2SIK10A, 2SI05AB-8" Vent Valve; January 6, 2005

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CR 328116; Foreign Objects Found in 2B Steam Generator Secondary Side; April 24, 2005
CR 328197; Foreign Objects Identified in Secondary Side of 2C SG; April 24, 2005
CR 329131; Foreign Objects Found in 2C Steam Generator at TSP 08H-A2R11; April 27, 2005
CR 186210; Foreign Material Exclusion-2A Steam Generator Preheater Inspection Foreign Objects; November 12, 2003
CR 305170; Unit 2 Steam Generator Secondary Side Cover ASME Code Issue; February 24, 2005
CR 320950; 2FE-0926 Boric Acid Leakage Orifice Connection, Repaired by Tool Pouch; April 4, 2005
CR 328671; Particles Vacuumed Following Lower Core Plate Inspection; April 26, 2005
CR 153405; Issue with 4 ISI Weld Exams Performed During A2R09; April 10, 2003
CR 181553; Risk Informed ISI Document Control Issue; October 17, 2003
CR 327429; North RVLIS Vent Plug Seized Due to Boron Leakage; April 22, 2005
CR 322632; 2PT-0150 HP Isolation Valve Boric Acid Leakage Repaired by Tool Pouch; April 8, 2005
CR 322688; 2RC025B Packing Boric Acid Leakage Repaired by Tool Pouch; April 8, 2005

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WO 99273255; 2CV836A Disassemble and Inspect per ER-400 as a Contingency; November 5, 2003
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WPS 8-8-GTSM; Revision 0
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PQR; A-004; February 8, 2000

PQR; A-003; February 8, 2000
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EXE-PDI-UT-1; Ultrasonic Examination of Ferritic Pipe Welds in Accordance with PDI-UT-1; Revision 4

Documents Associated with Disposition of Relevant Indications

VT-2-1.1 Visual Examination Data Form; Component ID: 2CV460; April 22, 2002
VT-2-1.1 Visual Examination Data Form; Component ID: 2CV8160; April 22, 2002
2002-02-08; ASME Section XI Bolted connection Evaluation; April 25, 2002
VT-2 Visual Examination Record; Component ID: 2CV123; November 7, 2003

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ED-BRW-05-0007; Braidwood Unit 2 Steam Generator Inspection Degradation Assessment and Condition Monitoring Input Checklist for A2R11; Revision 1
EA-AP-420-0051; Conduct of Steam Generator Management Program Activities; Revision 5
EC 355159; Evaluation of Foreign Objects not Retrieved from the Unit 2 Steam Generators - A2R11; Revision 0
ED-BRW-04-0003; Braidwood Unit 2 A2R10 Condition Monitoring and Operational Assessment Report; February 12, 2004
ED-BRW-05-0009; Braidwood Unit 2 Steam Generator Inspection Degradation Assessment and Condition Monitoring Input Checklist for A2R11; Revision 3
2FW-02; Inservice Inspection Isometric of Feedwater Lines 2FW03DA-16" and 2FW86AA-16", Inside Containment and Safety Valve Room Loop 1
ER-AP-331-1001; Boric Acid Corrosion Control (BACC) Inspection Locations, Implementation and Inspection Guidelines; Revision 1
ER-AP-331-1002; Boric Acid Corrosion Control Program Identification, Assessment, and Evaluation; Revision 1
Amendment No. 135 to NPF-77; Braidwood Station, Units 1 and 2 - Issuance of Exigent Amendments Re: Revision of Scope of Steam Generator Inspections for Unit 2 Refueling Outage 11; April 25, 2005

Nondestructive Certifications for Nondestructive Personnel:

Blum, William
Cochran, Lonnie
Miller, Jay
Reisewitz, Jack
Williams James

1R12 Maintenance Effectiveness

CR 211855; 1MS018B Failure Determined to be a MRFF (Reference CR 209129); March 30, 2004
CR 334585; 2D Main Steam Isolation Valve Problems; May 12, 2005
CR 340445; 2D Main Steam Isolation Valve Room Thermostat controlling Dampers Erratically; June 2, 2005
Drawing MS-1; Main Steam System; April 11, 2005; Revision 9
Maintenance Rule Expert Panel Scoping Determination; Braidwood Main Steam; May 5, 2005
Maintenance Rule - Performance Criteria; Braidwood Main Steam; May 5, 2005
Maintenance Rule - Evaluation History; Braidwood Main Steam; May 5, 2005

1R13 Maintenance Risk Assessments and Emergent Work Control

CR 324264; On-line Risk Mitigation - 0A Fire Pump and 'B' SX Train Inoperable; April 13, 2005
CR 324899; 0A Fire Pump Unavailable Greater than 7 Days; April 4, 2005
CR 324290; Gasket Material Dropped Into the 2A CW Pump Forebay; April 13, 2005
CR 325367; Unit 1 Instrument Failure (1PI-458 Pressurizer Pressure); April 16, 2005
CR 325459; Unit 1 Pressurizer Instrument Failure Results in Orange Online Risk; April 16, 2005
CR 326974; Safety Injection Full Flow Testing Failed to Meet Acceptance Criteria; April 20, 2005
CR 329667; Foreign Material Found in Safety Injection Cold Leg 2SI8822B - FME Event; April 27, 2005
CR 329915; Unit 1 Extent of Condition Review for Unit 2 IR 329667; April 28, 2005
CR 330000; Need to Revise 2BwOSR 3.5.2.7 Per Step in 2BwVSR TRM 2.5.C.3
CR 332947; 2C Reactor Coolant Loop Delta T Out of Tolerance; May 8, 2005
CR 333035; Review Extent of Condition of Byron Issue 325459; May 9, 2005
CR 338480; ASME Pressure Test Frequency Not Met (Reference TSR 3.0.C); May 25, 2005
CR 338503; Missed Hydrogen Monitor PT/VT Surveillance, Both Units Apply; May 25, 2005
BB-PRA-017.43; Risk Significance of Hydrogen Monitor PT/VT Surveillance at Byron/Braidwood; Revision 0
1BwOL TRM 3.4.f; Technical Requirements Manual LCOAR Structural Integrity TRM TLCO 3.4.f; Revision 2
BwOP RP-25; Aligning Main Control Board Controlling Channels for Work Activities; Revision 0
0BwOSR 0.1-0; Unit Common All Modes/At All Times Shiftly and Daily Operating Surveillance Data Sheet; Revision 14
Bus 232X Components Important to Shutdown Safety List; provided by licensee for A2R11
A2R11 Fuel Pool Cooling Contingency Plan and Required Equipment List for Bus 244 Outage; provided by licensee for A2R11
BwHP 4006-080; Alternate Power Source to the Unit Two Spent Fuel Pool Cooling Pump and Cubicle Coolers; Revision 1E1
0BwOA Refuel-3; Loss of Spent Fuel Pit Cooling, Unit 0; Revision 0

BwAR 1-1-A1; Spent Fuel Pit Pump Trip; Revision 5
BwAR 1-1-B1; Spent Fuel Pit Temperature High; Revision 6
NF-MW:04-0476; Calculation PNDCN-04-011, Braidwood Unit 1 Cycle 12 UET Calcnote; September 23, 2004
NF-MW:05-0082; Braidwood Unit 2 Cycle 12 UET; March 7, 2005
Drawing AC-7; AC One Line Diagram; May 6, 2003; Revision 3
Drawing —68; Diagram of Process Sampling PS Post Accident H_2 Monitoring System Unit 1; Sheet 7
Unit 0, 1 Risk Assessment; June 13, 2005
Braidwood Generating Station Plan of the Day; June 10, 2005
EC-AA-101-1004; 1B Diesel Generator On Line Work Window; Revision 2

1R14 Operator Performance During Non-Routine Evolutions and Events

BwAR 2-17-A1; HTR 27 LEVEL HI-2; Revision 7
BwOP HD-6; Removing High Pressure Feedwater Heater 27A/B From Service; Revision 13
CR 321000; Hi and Hi-2 Level in the 27A Heater; April 4, 2005

1R15 Operability Evaluations

CR 54582; A2001-01776 Cracked Turning Vane on A Train Control Room Ventilation; June 14, 2001
CR 76282; 1VP01CB Broken Turning Vane; September 24, 2001
CR 156091; 1VP01CB Turning Vane Materials Not to Desired Strength; May 28, 2003
CR 179749; Step Change in 2C Reactor Containment Fan Cooler [RCFC] Air Flow Rate; October 7, 2003
CR 185007; Foreign Material Exclusion - Degraded 2B and 2D RCFC Turning Vanes; November 5, 2003
CR 185469; 2C RCFC Turning Vane Degraded (Piece Detached); November 8, 2003
CR 261392; 1C RCFC Fan Turning Vane Found Cracked; October 7, 2004
CR 262227; Crack Next to Weld on 1VP01CB; October 10, 2004
CR 265273; RCFC Turning Vane Difference from Byron's Design; October 20, 2004
CR 322290; Unit 2 Emergency Hatch Outer Door Will Not Close; April 7, 2005
CR 322833; Unit 2 Containment Emergency Hatch Outer Door Leakage >100 Standard Cubic Feet Per Hour During Local Leak Rate Test
CR 326376; Audio Count Rate Speaker is Missing From U2 Containment; April 19, 2005
CR 326502; Potential Discrepancy in Actuator Weight for Valves 1/2AF024; May 20, 2005
CR 326978; 2B RCFC Turning Vane has 3 Cracks; April 21, 2005
CR 327975; Installed Wiring Size Does Not Match Design Drawings; April 23, 2005
CR 328095; Crack in 2C RCFC Turning Vane; April 23, 2005
CR 331605; Generate WO for Required Inspection of Valve 1SI8822B; May 3, 2005
EC 355219; Fuel Impact - Debris Found in Safety Injection Line by Valve SI8822B; April 30, 2005
EC 355229; Foreign Material Found in Safety Injection Cold Leg 2SI8822B; May 2, 2005
Operability Evaluation 05-002; For U1/U2 AF 024 Operators Weigh More Than Analyzed
Operability Evaluation 05-004; Potential Impact of Foreign Material in Unit 1 Emergency Core Cooling System Piping; Revision 0

2BwGP 100-6; Refueling Outage; Revision 18
BwISR 3.3.1.11-301; Verification of Nuclear Instrumentation System Source Range/ Audio Count Rate Containment Indications; Revision 7
2BwOSR 3.6.2.1-3; Primary Containment Type B Local Leak Rate Test of Emergency Personnel Hatch Airlock; Revision 4

1R16 Operator Workarounds

2BwOS RC-4; Unit Two Control Rod Insertion Limit Surveillance; Revision 2
2BwOSR 3.1.4.2; Unit Two Movable Control Assemblies Surveillance; Revision 7 Continuous Use
CR 248658; Rod Insertion Limit Low Annunciator Inoperable; August 31, 2004
CR 24979; P/A Converter Failed to Correctly Track Control Rod Movement; September 3, 2004
CR 282946; Blown Fuse When Working on 1PR035; December 15, 2004
CR 285012; Alarm Toggling on 1TT-VP022; December 22, 2004
CR 285396; Diesel Generator 1A Trouble/Fail to Start Alarm Still Toggling; December 24, 2004
CR 285709; Received 2B Diesel Generator Trouble Alarm Due to ; December 27, 2004
CR 286132; Power Range Channel Deviation Alarming; December 28, 2004
CR 294658; Demonstrate Power Uprate Impact on Feedwater Response; November 2, 2002
CR 294838; Concern on Main Control Room Annunciators; January 27, 2005
CR 294834; Access Doors in Auxiliary Building Locked; January 27, 2005
CR 295229; Plant Equipment Not Accessible in U-1 Main Steam Isolation Valve Rooms; January 28, 2005
CR 296727; Valve Shows Duel in Main Control Room (Closed Locally); February 2, 2005
CR 297191; Power Range Deviation Alarms; February 2, 2005
CR 298070; Low Point Drain Alarm Toggling; February 5, 2005
CR 298763; Main Control Room Distractions In Variance; February 1, 2005
CR 299203; Unplanned Limiting Condition for Operation Requirement 1PRllJ Hi Alarm; February 8, 2005
CR 300842; Secondary Emergency Level Control Valve are Set Too Close to Hi-Hi Level Setpoints; February 10, 2005
CR 301150; 13B Feedwater Heater Has Operated on Its Emergency Level Control Valve for More Than 1 Week; February 14, 2005
CR 301250; Annunciator Power Supply Trouble alarm; February 14, 2005
CR 301370; Emergency Drain Valve Cycled Open; February 14, 2004
CR 301389; Hi Level Alarm Needs Calibration; February 14, 2005
CR 301207; Numerous Radiation Alarms from 1PR27J; February 16, 2005
CR 303429; New Reactor Containment Fan Cooler ; February 19, 2005
CR 303558; Additional Followup Actions Recommended; February 13, 2005
CR 305867; IMD Work Impacts Unit 2 Feedwater Flow; February 25, 2005
CR 309408; Unit 1 Boric Acid Tank Level Low Alarm; March 7, 2005
CR 311430; Question on Complacency for Main Control Room Annunciators; March 11, 2005
CR Unit 1 Main Control CRT #2 Screen is Blank; March 23, 2005
CR 321442; 2HD038A Not Annunciating Expected Alarms; April 5, 2005

CR 327611; Several Annunciators - 100 Received on U-2; April 22, 2005
CR 328104; Annunciator Panel Does Not Always Chime; April 24, 2005
CR 328110; No Chime When Acknowledging Alarms/Tests; April 24, 2005
CR 331874; Unit 2 P/A Converter Malfunction on Bank K; May 4, 2005
CR 333066; Engineering Review Seasonal Spot Cooler Alignment; May 1, 2005
CR 333070; System Engineering Investigate Other Stations Rod Drive Cooling; May 1, 2005
OP-AA-102-103; Operator Work-Around Program; Revision 1
Operator Workaround Minutes; 10/2000-5/2005
Braidwood Closed Operator List; A1R11 WO571321 WO is Currently in Forced Outage; Closure Date October 15, 2004
Operator Work Around Status Update; May 16, 2005

1R17 Permanent Plant Modifications

EC 350933; Revise C-9 Interlock Setpoint (Condenser Vacuum) Summer Readiness Issue; Revision 000
EC 350934; Rescale Unit 2 C-9 Interlock; Revision 000

1R19 Post-Maintenance Testing

BwOP DB-11; Diesel Generator Startup; Revision 29
BwOP HD-1; Heater Drain System Startup; Revision 19
2BwOS TRM 2.7.a.1; Unit 2 Auxiliary Feedwater Diesel Prime Mover Performance Surveillance
BwOSR 3.1.4.2; Unit Two Movable Control Assemblies Surveillance; Revision 7
BwVSR 5.5.8.AF.2; Unit One Diesel Driven Auxiliary Feedwater Pump ASME Quarterly Surveillance; Revision 9
MA-MW-736-600; Torquing ad Tightening of Bolted Connections; Revision 1
OP-AA-106-101-1006; Issue Resolution Documentation Form; Revision 1
CR 326974; A2R11 - SI Full Flow Testing Failed to Meet Acceptance Criteria; April 20, 2005
CR 327010; Instrument 2FE-0983 Reading Low During Testing; April 21, 2005
CR 328241; Transient Voltage Response Requirement for SX Pump Start; April 24, 2005
CR 328710; EMD Cannot Fit Torque Wrench to Starter Motors; May 26, 2005
CR 330665; A2R11 LL Diesel Generator Frequency Change When Speed/Voltage Control Restored; May 1, 2005
CR 331108; 2B Auxiliary Feedwater Diesel Aborted Start Attempt During Prime Mover Surveillance; May 2, 2005
CR 340043; Delay of 1B Heater Drain Motor Restoration; June 1, 2005
EC 348884; Replace ESF Cabinet Sequence Timers [Eagle Timers]; March 11, 2005
WO 98035905; Diesel Generator Governor Set-up Following Governor Replacement; April 24, 2005
WO566743; 2AF01PB-K 12 Year PM for Auxiliary Feedwater Diesels; April 21, 2005
WO 638369; 2B Diesel Generator 24 Hour Load Test and ECCS Surveillance; May 1, 2005
WO 639984; 2A Diesel Generator Full Load Rejection and Simulated SI in Conjunction with Undervoltage During Load Testing; April 25, 2005

WO 640386; 2A Diesel Generator Loss of ESF Bus Voltage with No SI Signal; April 25, 2005
WO 640387; 2A Diesel Generator ECCS Sequencer Surveillance; April 26, 2005
WO 641257; U2 Auxiliary Feedwater Diesel Prime Mover Performance Surveillance; May 2, 2005
WO 651087; Diesel Generator 18 Month Overspeed Trip Test
WO 676449; Safety Injection to Cold Leg Check Valve Surveillance; April 19, 2005
WO 676499; Safety Injection to Cold Leg Check Valve Surveillance; April 19, 2005
WO 787685; Set - Unit 2 Diesel Driven Auxiliary Feedwater Pump American Society of Mechanical Engineers Quarterly Surveillance; May 1, 2005
WO 803429; Safety Injection Cold Leg Flow Balance Test; April 27, 2005
WO 813647; IST-1B Diesel Generator Operability Monthly

1R20 Refueling and Other Outage Activities

CR 310545; Unit 2 Power Range HV Plateau Results Not as Expected; March 8, 2005
CR 327611; Several Annunciators - 100 Received on U2 and Common Panels; April 22, 2005
CR 331256; A2R11LL - 2B Feedwater Pump Lube Oil System Troubleshooting; May 3, 2005
CR 331258; Unit 2 Reactor Head Vent Valve Leaking; May 2, 2005
Plant Operations Review Committee Meeting Minutes; A2R11 Shutdown Risk; April 12, 2005

1R22 Surveillance Testing

BwMP 3300-052; 18 Month Visual Inspection of All Safety Related Fire Dampers; Revision 8
BwMP 3300-052A10; Work Performance Checklist; Revision 2
2BwOA PRI-8; SX Malfunction Unit 2; Revision 102
2BwOL 3.7.8; LCOAR SX System Technical Specification LCO 3.7.8; Revision 3
BwOP AF-7; Auxiliary Feedwater Pump B (Diesel) Startup on Recirc; Revision 26
BwOP AF-8; Auxiliary Feedwater Pump B (Diesel) Shutdown; Revision 23
BwOP CV-19; Switching Charging Pumps/ Revision 10
BwOP SX-E2; Electrical Lineup - Unit 2 SX system; Revision 8
BwOP SX-M2; Operating Mechanical Lineup Unit 2; Revision 24
BwOSR 3.3.1.4-1; Unit Two Solid State Protection System, Reactor Trip Breaker, and Reactor Trip Bypass Breaker Bi-monthly Surveillance (Train A); Revision 17
2BwOSR 3.7.5.4-2; Unit Two Diesel Driven Auxiliary Feedwater Pump Surveillance; Revision 8
2BwOSR 3.7.8.1; Unit Two SX System Surveillance; Revision 10
1BwVSR 5.5.8.CV.2; ASME Surveillance Requirements for 2B Centrifugal Charging Pump and Check Valve 2CV8480B Stroke Test; Revision 4
CR 325910; Corrosion on Unprotected Portions of Auxiliary Feedwater Pipe at 26-Line 357'; April 17, 2005
WO 608594 01; 10 Month Visual Inspection of All Safety Related Fire Dampers (1A); April 14, 2005
WO 642086 01; Full Flow Test and Equipment Response Time of Auxiliary Feedwater Pumps; April 16, 2005

WO 780835; Turbine Driven Feedwater Pump Mechanical Overspeed Trip Surveillance; May 11, 2005
WO 807544 01; Unit 2 Solid State Protection System, Reactor Trip Breaker, Reactor Trip Bypass Breaker Bi-Monthly Train A; June 29, 2005;
WO812772 01; U2 Diesel Driven Auxiliary Feedwater Pump Monthly Surveillance; June 9, 2005

1R23 Temporary Plant Modifications

CR 322888; Leak Repair on 1A Feedwater Pump Unsuccessful; April 9, 2005
CC-AA-404; Maintenance Specification: Application Selection, Evaluation and Control of Temporary Leak Repairs; Revision 7
CC-AA-404; Temporary Leak Repair Permit WO 790979; IR 310602
OP-AA-106-101-1006; Issue Resolution Documentation Form; March 14, 2005
1A Feedwater Pump Casing Leak Temporary Repair Sequence
Braidwood 12 Week Rolling Network; 1A Motor Driven Feedwater Pump Repair; March 31, 2005

2OS1 Access Control to Radiologically Significant Areas; and

2OS2 ALARA Planning And Controls

RWP 10004547; A2R11 Steam Generator Eddy Current Testing and All Tube Repairs; Revision 1
RWP 10004529; A2R11 Reactor Head CRDM Volumetric Inspection; Revision 1
RWP 10004546; A2R11 Install and Remove Steam Generator Nozzle Covers; Revision 1
RWP 10005140; A2R11 Manway and Diaphragm Removal, Installation & Bolt Cleaning; Revision 0
A2R11; Steam Generator Project ALARA Plan
AT 270723; Self-Assessment Access Control To Radiologically Significant Areas; dated February 1, 2005
AT 270726; Self-Assessment ALARA Preparation and Control; dated March 30, 2005
NOS Objective Evidence Reports; Radiation Dose Control, HRA Controls, Radworker Practices, and Radiation Protection; dated February-March 2005
CR 271655; Co-58 Detected in TB Fire and Oil Sump; dated November 8, 2004
CR 272030; A1R11 Noble Gas Problems in Containment; dated October 6, 2004
CR 291168; Increased Dose Rates On Drain Causes HRA; dated January 15, 2005
261937; Root Cause Analysis-Waste Gas Release; dated November 5, 2004
CR 306029; Elevated U2 Containment Rads Resulting in 2PR11J Alarm Condition; dated February 26, 2005
CR 309593; NOS Identified Survey Maps Outdated; dated March 7, 2005
CR 322667; Workers ID Elevated Dose Rates Near Spent Fuel Pool; dated April 8, 2005
CR 317593; Questions About Gaseous Releases; dated March 25, 2005
CR 317979; LHRA Barriers For Notched Wall Area Inadequate; dated March 28, 2005
CR 316242; Fuel Pool Activity Higher Than Normal; dated March 23, 2005
CR 312795; Two EMD Personnel Found an Unposed Area; dated March 15, 2005
CR 310469; Apparent Cause Evaluation; dated August 11, 2004

CR 324964; MGPAC Did Not Lock Out Worker With High Dose Rate Alarm; dated April 14, 2005
CR 325442; MGPAC Rad Access Control Program Is Not Locking Out High Rate; dated April 16, 2005
RP-AA-400; ALARA Program; Revision 3
RP-AA-220; Bioassay Program; Revision 2
RP-AA-400-1001; Establishing Collective Radiation Exposure Estimates and Goals; Revision 0
RP-AA-301; Radiological Air Sampling Program; Revision 0
RP-AA-4002; Radiation Protection Refuel Outage Readiness; Revision 1
RP-AA-401; Operational Alara Planning and Controls; Revision 4
RP-AA-460; Controls for High and Very High Radiation Areas; Revision 7
RP-AA-270; Prenatal Radiation Exposure; Revision 2
RP-AP-401-1403; Writers Guide for Preparation of Steam Generator Primary Side Maintenance ALARA Plan; Revision 0
RP-AP-401-1402; Writers Guide for Preparation of Steam Generator Secondary Side Maintenance ALARA Plan; Revision 0

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

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Focus Area Self-Assessment Report # 221202; dated January 7, 2005
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CR 328451; Tritium Indicated in Samples Taken from Onsite Culvert; dated April 1, 2005
CR 253179; 1PR17J Gas Channel Spiking; dated September 15, 2004
CR 241885; Iodine Channel Has Failed Auto C/S Two Times in Past 7 days; dated August 5, 2004
CR 236640; 2PR27J Failed Automatic and Manual Check Source; dated July 16, 2004
CR 250635; U1 RCS I-131 Exceeds Action Level 2 Value; dated September 7, 2004
CR 333032; 1AR11J Failed Its Check Source; dated May 9, 2005
CR 320990; 1PR11J Particulate Monitor in Red-Unplanned LCO; dated April 4, 2005
CR 261937; Increased Radioiodine Levels in Waste Gas Decay Tank Releases; dated October 9, 2004
CR 334505; Potential Error Traps in Liquid Release Procedure; dated May 12, 2005

2PS3 Radiological Environmental Monitoring Program and Radioactive Material Control Programs

Offsite Dose Calculation Manual; Revision 3; dated January 2002
2004 Annual Radiological Environmental Operating Report, BW050043; dated May 11, 2005
Report of Audit dated May 15, 2003: NUPIC Audit/Survey Number 18668, Audit/Survey of Teledyne Brown Engineering Environmental Services, Knoxville, TN, conducted on March 25 - 27, 2003
Revision/Addendum to NUPIC Audit/Survey Number 18668; dated August 11, 2003
Closeout to NUPIC Audit/Survey Number 18668; Corrective Actions Evaluated and Found Acceptable; dated December 18, 2003

Field Rotameter Calibration Datasheets, Environmental, Inc., 2004
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4OA1 Performance Indicator Verification

Nuclear Energy Institute Document 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 3

4OA2 Identification and Resolution of Problems

Braidwood Quarterly SHIP Report; 4th Quarter 2004
CAPCO Trend Review, 8/1/2004 through 1/31/2005
LS-AA-125 Corrective Action Program, Revision 8
LS-AA-125-1005 Coding and Analysis Manual, Revision 4
ER-AA-520 Instrument Performance Trending, Revision 3
CR 266594; A1R11 LL - AF014 Leakage Trend, and Assignment 04
CR 292238; Increased Trend in Recorded Temperatures for Bulletin 88-08
CR 292984; Inspect Pressurizer Heater Contractor Corrective Action
CR 293010; Inspect Pressurizer Heater Contractor Corrective Action
CR 307610; Potential Trend for Number of Leak IRS on the HD System
CR 308456; Several PM's Associated with U-0 SAC Required Second Deferral
CR 310161; B4 Trend Code: 2LT-RY046 as Found Values OOT High
CR 311133; B4 Trend Code: 2LT-RY049 as Found Values OOT HI

Review of the Licensee Refueling Outage (A2R11) Condition Reports (one annual sample)

LS-AA-125 Corrective Action Program, Revision 8
CR 300271 South Hoist Load Cell Malfunctioning SFPBC
CR 327424 SFPBC Load Cell Adverse Condition Monitoring
CR 327243 Erratic Indiction on FHBC Hoist Load Indicator
CR 327454 NOS ID's Process Improvement - Documenting FH Interlocks
CR 327453 FHB Crane Load Cell Overload Tripped
CR 327439 Refueling Machine Tripping on Overload
CR 327438 NOS ID's Approved SFP Bridge Crane ACM References Wrong Procedure
CR 327456 Refuel Machine Tripping
CR 327485 Fuel Handling Team Experienced Problems at Core
OU-AP-204 Operation of the Transfer System, Fuel Handling Activities in the Spent Fuel Pool for Byron and Braidwood, Rev. 1c
UFSAR Section 9.1.4 Fuel Handling System, Rev. 1
OU-AP-204 Operation of the Transfer System, Attachment 13 Rev. 1c
OU-AP-204 Operation of the Transfer System, Attachment 4 Rev. 1b
CR 327404; Water Accumulation in Station Air Receiver
CR 332775 Unexpected Result in 2C FW Pump Lube Oil Testing
CR 332896 Anomalies with 2C FW Pump Lube Oil System During Startup

CR 328734 Valve was Over Thrusted During Votes Testing
CR 329040 Oxidation on Rear Portion of 2RD05J Card Frame Termi-Points
CR 333086 Valve Shows Dual When Full Closed
CR 333093 Inspect RD Card Frames in A2R12

4OA3 Event Followup

CR 318027 Unit 2 Main Generator Tripped Causing Unit 2 Reactor Trip
CR 318027 Prompt Investigation for Unit 2 Reactor Trip due to Generator C-Phase Main Lead Bushing Failure
CR 318027 Root Cause Investigation for the Unit 2 Main Generator Tripped Causing Unit 2 Reactor Trip
CR 318030 Relief For 27B Heater Lifted due to Unit Trip
CR 318039 2PR06J Went into Alert After the Unit 2 Reactor Trip
CR 318044 2CV121 Worked Erratically in Auto After Unit 2 Reactor Trip
CR 318065 Unusual Event Declared Due to H2 Leak on Unit 2 Generator
CR 318048 2AF005H Failed Full Open in MCR After Unit 2 Trip
CR 318140 IMD Personnel in Unit 2 Containment During U2 Reactor Trip
CR 318193 Field Operator Reported Unexpected Alarms on 2B AF PP
CR 318594 VCT Level High Causing LCO 3.3.9 Entry Post U2 Reactor Trips
CR 186222 Main Generator T3 Phase Bushing Degraded
2BwGP 100-A13 Reactor Trip Root Cause Determination, Rev. 6, 3/28/2005

4OA5 Other

Pressurizer Penetration Nozzles and Steam Space Piping Connections in U. S. Pressurized Water Reactors (TI 2515/160)

Exelon letter July 27, 2004; Initial Response to NRC Bulletin 2004-01, Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors
ER-AA-335-015; VT-2 Visual Examination; Revision 3
TQ-AA-122; Qualification and Certification of Nondestructive Personnel; Revision 1
A2R11-036; VT2 Visual Examination Record; April 19, 2005

Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (TI 2515/150)

MRP-89; Materials Reliability Program: Demonstrations of Vendor Equipment and Procedures for the Inspection of Control Rod Drive Mechanism Head Penetrations; September 2003
Exelon letter dated September 11, 2002; Exelon/AmerGen 30-Day Response to NRC Bulletin 2002-02, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs
WO 00582805; Review U2 REACTOR Vessel EFPY Projections and PT/LTOP Curves; May 27, 2004
DIT-BRW-2003-0013; Unit 1 and Unit 2 Programmed Tref Scaling History; March 24, 2003

WDI-UT-010; Intraspect Ultrasonic Procedure for Inspection of Reactor Vessel Head Penetrations, Time of Flight Ultrasonic, Longitudinal Wave and Shear Wave; Revision 10.
WDI-STD-101; RVHI Vent Tube J-Weld Eddy Current Examination; Revision 4
WDI-UT-011; IntraSpect Nondestructive Procedure for Inspection of Reactor Vessel Head Vent Tubes; Revision 7

Operational Readiness of Offsite Power (TI 2515/163)

AQ-68; Division Specific Degraded Voltage Analysis; November 17, 1997/December 3, 1999
0BwOA ELEC-1; Abnormal Grid Conditions Unit 0
CR 218470; NRC Offsite Power System Operational Readiness Inspection; May 3, 2004
CR 220999; Unit Output Swing Due to Grid Conditions; May 13, 2005
CR 333069; OE20574 - Relay Setting Could Cause Early Separation; May 9, 2005
OP-AA-107-107; Switchyard Control; Revision 1
OP-MW-108-107-1001; Station Response to Grid Capacity Conditions; Revision 0
OP-MW-108-107-1001; Station Response to Grid Capacity Conditions; Revision 1
EC-AA-101; On-Line Work Control Process; Revision 10
EC-AA-107; Seasonal Readiness; Revision 1

NRC Identified

CR 277240; Bolting on Right Bank Intercooler - Improper Thread Engagement; November 29, 2004 [Maintenance Effectiveness]
CR 324056; Appendix R Light 0-27 Found Unplugged; April 12, 2005 [Fire Protection]
CR 324246; NRC Observations Noted on 2A SX Pump (2SX01PA); April 12, 2005 [Refueling and Other Outage Activities]
CR 324270; Fire Extinguisher A-8-27C Tag, Missing Quarterly Inspection; April 12, 2005 [Fire Protection]
CR 324309; Loose Bolt Found on 2SI01PA Coupling Guard; April 13, 2005 [Refueling and Other Outage Activities]
CR 326407; Train Separation 2A/2B Residual Heat Removal Pump Room Concern; April 19, 2005 [Fire Protection]
CR 326654; Fire Extinguisher A-2-3 was Missing Quarterly Inspection Sign Off; April 19, 2005 [Fire Protection]
CR 326989; NRC Field Report of Issues Discovered on April 19, 2005; April 19, 2005 [Refueling and Other Outage Activities]
CR 327201; Temporary Penetration Seals Not Installed Per Design Detail; April 8, 2005 [Fire Protection]
CR 328648; Incomplete Scope of Work Assigned WO 769259 (2RY455B); April 25, 2005 [Refueling and Other Outage Activities]
CR 329025; Questions About Protected Equipment Asked by Resident NRC; April 26, 2005 [Refueling and Other Outage Activities]
CR 329756; Several Fire Seals Recently Noted as Not Meeting Design; April 28, 2005 [Refueling and Other Outage Activities]
CR 330177; NRC Question WRT 1A SX Pump L.O. Pressure; April 26, 2005 [Refueling and Other Outage Activities]

CR 330397; NRC Concerns with Cracked Turning Vanes on Reactor Containment Fan Coolers [Operability Evaluation]
CR 330704; NRC Questions for Scaffolding in the Plant; April 28, 2005 [Refueling and Other Outage Activities]
CR 330819; Results of U2 Containment Final Walkdown; May 2, 2005 [Refueling and Other Outage Activities]
CR 331605; Generate WO for Required Inspection of Valve 1SI8822B; May 3, 2005 [Maintenance Effectiveness]
CR 331933; Possible Inadequate Third Engagement of Intercooler CVR Bolts; February 29, 2004 [Maintenance Effectiveness]
CR 331935; Intercooler CVR Bolts, Possible Inadequate Thread Engagement; February 29, 2004 [Maintenance Effectiveness]
CR 331937; Possible Inadequate Thread Engagement, Intercooler Covers; February 29, 2004 [Maintenance Effectiveness]
CR 331938; Possible Inadequate Thread Engagement, Intercooler Covers; February 29, 2004 [Maintenance Effectiveness]
CR 334561; Documentation of 2B Auxiliary Feedwater American Society of Mechanical Engineers Preconditioning; May 2, 2005 [Post Maintenance Testing]
CR 335587; 2CV Pump Runtime Meter Broke; May 16, 2005 [Maintenance Effectiveness]
CR 338253; NRC Concern Over Tracking of Response to Grid Conditions; May 5, 2005 [TI 2515/163]
CR 338923; NRC Identified Recurring Issues Rather Than Station People; May 27, 2005 [Operability Evaluation]
Issue 344595; Superceded Figure Found in Fire Protection Report; June 16, 2005 [Fire Protection]
Issue 344710; Incorrect Location Identified in Pre Fire Plan (Zone 1D-77); June 16, 2005 [Fire Protection]
Issue 344717; Fire Protection Hose Stations Not Shown of Fire Protection Report Design Drawings; June 16, 2005 [Fire Protection]

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access and Management System
ALARA	As Low As Is Reasonably Achievable
ASME	American Society of Mechanical Engineers
BACC	Boric Acid Corrosion Control
BwAR	Braidwood Annunciator Response Procedure
BwISR	Braidwood Instrument Surveillance Requirement Procedure
BwMP	Braidwood Maintenance Procedure
BwOA	Braidwood Abnormal Operations Procedure
BwOP	Braidwood Operating Procedure
BwOS	Braidwood Operations Surveillance Procedure
BwOSR	Braidwood Operating Surveillance Requirement Procedure
BwVSR	Braidwood Engineering Surveillance Requirement Procedure
CFR	Code of Federal Regulations
CR	Condition Report
DOST	Diesel-Generator Oil Storage Tank
EDY	Effective Degradation Years
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
ET	Eddy Current
HRA	High Radiation Area
ISI	Inservice Inspection
LER	Licensee Event Report
NFPA	National Fire Protection Assosication
NRC	Nuclear Regulatory Commission
OSP	Offsite Power
PARS	Publicly Available Records
PI	Performance Indicator
PWR	Pressurized Water Reactor
RCFC	Reactor Containment Fan Cooler
REMP	Radiological Environmental Monitoring Program
RETS/ODCM	Radiological Environmental Technical Specifications/Offsite Dose Calculation Manual
RP	Radiation Protection
RVCH	Reactor Vessel Closure Head
RWP	Radiation Work Permit
SDP	Significance Determination Process
SG	Steam Generator
SX	Essential Service Water
TI	Temporary Instruction
TS	Technical Specification
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Examination
VHP	Vessel Head Penetration
VHRA	Very High Radiation Area
WO	Work Order