UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

November 3, 2011

EA-11-167

Mr. Michael J. Pacilio
Senior Vice President, Exelon Generation Company, LLC
President and Chief Nuclear Office (CNO), Exelon Nuclear
4300 Warrenville Road
Warrenville, IL 60555

SUBJECT: BYRON STATION, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000454/2011004; 05000455/2011004

Dear Mr. Pacilio

On September 30, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Byron Station, Units 1 and 2. The enclosed inspection report documents the inspection findings which were discussed on October 13, 2011, with Mr. B. Adams and other members of your staff.

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

Based on the results of this inspection, two NRC-identified findings of very low safety significance (Green) that involved violations of NRC requirements were identified. The NRC identified an additional Green finding that was associated with a Severity Level IV violation of NRC requirements evaluated through the traditional enforcement process. However, because of their very low safety significance, and because these issues were entered into your corrective action program, the NRC is treating these violations as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the subject or severity of an NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Byron Station. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Byron Station. The information you provide will be considered in accordance with Inspection Manual Chapter 0305.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Eric R. Duncan, Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50-454; 50-455
License Nos. NPF-37; NPF-66

Enclosure: Inspection Report No. 05000454/2011004 and 05000455/2011004
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-454; 50-455
License Nos:	NPF-37; NPF-66
Report Nos:	05000454/2011004 and 05000455/2011004
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	Byron, IL
Dates:	July 1, 2011, through September 30, 2011
Inspectors:	B. Bartlett, Senior Resident Inspector J. Robbins, Resident Inspector R. Ng, Project Engineer T. Bilik, Reactor Inspector J. Cassidy, Senior Health Physicist D. Jones, Reactor Inspector J. Gilliam, Reactor Inspector J. Nance, Reactor Engineer C. Thompson, Resident Inspector, Illinois Emergency Management Agency B. Metrow, ASME Inspector, Illinois Emergency Management Agency
Approved by:	E. Duncan, Chief Branch 3 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS

Inspection Report 05000454/2011004, 05000454/2011004; 07/01/2011 - 09/30/2011; Byron Station, Units 1 & 2; Maintenance Risk Assessment and Emergent Work Control; Identification and Resolution of Problems; Other Activities

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Three Green findings were identified by the inspectors. The findings were considered Non-Cited Violations (NCVs) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). Assigned cross-cutting aspects were determined using IMC 0310, “Components Within the Cross-Cutting Areas.” Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear power Plants,” when licensee personnel failed to accurately assess plant risk during maintenance activities. The inspectors determined that the licensee failed to identify and take actions required to address an increase in risk when the Unit 2 Component Cooling Water (CC) heat exchanger was removed from service. Specifically, for 0.6 days the Unit 2 CC heat exchanger was removed from service and the plant remained in a Green risk status although the licensee's maintenance risk management procedure prescribed that a Yellow risk status be entered and that certain Risk Management Actions (RMAs) be taken. Upon identification and notification by the NRC inspectors, licensee personnel revised the plant risk status from Green to Yellow and took the appropriate RMAs. The issue was entered into the licensee’s corrective action program as Issue Report (IR) 1262639.

  The performance deficiency was determined to be more than minor because it was associated with the Human Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The performance deficiency was also determined to be more than minor because the finding was similar to IMC 0609, Appendix E, Example 7.e, and resulted in actual plant risk being in a higher risk category established by the licensee than had been previously declared. The Byron Standardized Plant Analysis Risk (SPAR) model Version 8.18 and SAPHIRE model Version 8.0.7.17 was used to calculate an Incremental Core Damage Probability Deficit (ICDPD) for the condition of the Unit 2 CC heat exchanger being unavailable for 0.6 days. The result was an ICDPD of less than 5E-7. Based on the analysis, the finding was determined to be of very low safety significance (Green). This finding had a cross-cutting aspect in the

Work Control component of the Human Performance cross-cutting area [H.3.(a)] because the licensee failed to appropriately incorporate risk insights when the Unit 2 CC heat exchanger was removed from service. (Section 1R13)

- Severity Level IV. The inspectors identified a finding of very low safety significance (Green) and an associated Severity Level IV NCV of 10 CFR 50.59,"Changes, Tests, and Experiments," when licensee personnel failed to obtain a license amendment prior to implementing a proposed change to the plant that resulted in a more than minimal increase in the likelihood of occurrence of a malfunction of a structure, system or component important to safety previously evaluated in the Updated Final Safety Analysis Report (UFSAR). Specifically, the licensee performed a modification to the facility that permitted the Unit 1 and Unit 2 "A" Auxiliary Feedwater (AF) trains to be shared between units and the 10 CFR 50.59 evaluation that was performed reached the erroneous conclusion that prior NRC approval was not required. The licensee issued a Standing Order to modify the Emergency Operating Procedure which governed the use of the modification and planned to submit a License Amendment Request (LAR) to the NRC for this design change. The issue was entered into the licensee's corrective action program as IR 1257908.

  The violation was determined to be more than minor because the inspectors determined that the change required prior NRC approval. Violations of 10 CFR 50.59 are dispositioned using the traditional enforcement process because they are considered to be violations that potentially impede or impact the regulatory process. However, if possible, the underlying technical issue is evaluated through the SDP to determine the severity of the violation. In this case, the inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a, for the Mitigating Systems Cornerstone. Specifically, the inspectors answered "Yes" to Question 1 of the Mitigating Systems Cornerstone column of the Phase 1 worksheet because the inspectors concluded that this was a change confirmed not to result in the loss of operability. Based upon this Phase 1 screening, the inspectors concluded that the issue was of very low safety significance (Green). In accordance with Section 6.1.d.2 of the NRC Enforcement Policy, this violation is categorized as Severity Level IV because the resulting changes were evaluated by the SDP as having very low safety significance. This finding had a cross-cutting aspect in the Operating Experience component of the Problem Identification and Resolution (PI&R) cross-cutting area [P.2.(b)] because the licensee failed to make adequate use of known industry operating experience in the screening of a modification prior to installation. (Section 4OA2.3)

- Green. The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to properly analyze the configuration of the Essential Service Water (SX) connections to the AF pumps. Specifically, a section of the piping was intentionally maintained empty (voided), but was not previously analyzed. This condition existed since initial plant construction. The issue was entered into the licensee's corrective action program as IR 1172938.

  The finding was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attribute of Design Control and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the unverified configuration might have rendered each of the AF pumps inoperable. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase - 1 Initial Screening and Characterization of Findings,” Table 4a, for the Mitigating Systems Cornerstone. Specifically, the inspectors answered “Yes” to Question 1 of the Mitigating Systems Cornerstone column of the Phase 1 worksheet because the inspectors concluded that this finding was confirmed not to result in a loss of operability. This conclusion was reached after reviewing tests performed by the licensee. The tests demonstrated there was reasonable assurance that the AF system would perform its safety function in the installed configuration. Additionally, the licensee filled the voided sections of pipe, restoring compliance with the licensed design basis. The inspectors did not identify a cross-cutting aspect associated with this finding because it was not indicative of current licensee performance. (Section 4OA5)

B. <u>Licensee-Identified Violations</u>

No violations of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power during this inspection period.

Unit 2 operated at or near full power from the beginning of the inspection period until September 18, 2011, when the unit was shut down for a planned refueling outage. At the end of the inspection period, the unit remained in the planned refueling outage.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

.1 Readiness for Impending Adverse Weather Condition – Severe Thunderstorm Watch & High Wind Conditions

a. Inspection Scope

Since thunderstorms with potential tornados and high winds were forecast in the vicinity of the facility for July 28, 2011, and September 28, 2011, the inspectors reviewed the licensee's overall preparations and protection for the expected weather conditions. Specifically, the inspectors assessed the licensee's readiness for adverse weather conditions with thunderstorms in the area during Unit 2 Train B diesel generator modification activities on July 28, 2011; and during high winds in the area with Unit 2 fuel moves scheduled on September 28, 2011.

The inspectors walked down the emergency alternating current power systems, because their safety-related functions could be affected or required as a result of high winds or tornado-generated missiles or the loss of offsite power. The inspectors determined whether the licensee staff's preparations conformed to site procedures and determined whether the staff's actions were adequate. During the inspection, the inspectors focused on plant-specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. The inspectors also reviewed a sample of corrective action program (CAP) items to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station corrective action procedures. Documents reviewed are listed in the Attachment.

This inspection constituted two readiness for impending adverse weather condition samples as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- Unit 2 Train B Direct Current (DC) Bus 212 while Unit 2 Train A DC Bus 211 and Unit 1 Train A DC Bus 111 were Crosstied; and
- Unit 2 Train A AF System while the Unit 2 Train B AF System was Out of Service.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, UFSAR, Technical Specification (TS) requirements, outstanding work orders (WOs), condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

These activities constituted two partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On September 26, 2011, the inspectors performed a complete system alignment inspection of the Unit 2 Train B safety injection system to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee’s probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment line ups, electrical power availability, system pressure and temperature indications, as appropriate, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected system functionality. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment.

These activities constituted one complete system walkdown sample as defined in IP 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Unit 1 Turbine Building 369′-0” General Area (Fire Zone 8.2-1);
- Unit 2 Turbine Building 369'-0" General Area (Fire Zone 8.2-2);
- Main Control Room (Fire Zone 2.1-0); and
- Division 21 Miscellaneous Electrical Equipment and Battery Room (Fire Zone 5.6-2).

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee’s fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant’s Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant’s ability to respond to a security event. Using the documents listed in the Attachment, the inspectors verified that 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 fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee’s CAP. Documents reviewed are listed in the Attachment.

These activities constituted four quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings of significance were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk-important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. The specific documents reviewed are listed in the Attachment to this report. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant areas to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- Unit 1 Main Steam Isolation Valve Vault Rooms;
- Unit 2 Main Steam Isolation Valve Vault Rooms;
- Turbine Building, Elevation 401' and below; and
- Auxiliary Building, Elevation 401'.

This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

No findings were identified.

.2 Underground Vaults

a. Inspection Scope

The inspectors reviewed underground manholes subject to flooding that contained cables whose failure could disable risk-significant equipment. The inspectors verified that the cables were not submerged, that splices were intact, and that appropriate cable support structures were in place. In those areas where dewatering devices, such as a sump pump, were used the inspectors determined whether the device was operable and level alarm circuits were set appropriately to ensure that the cables would not be submerged. In those areas without dewatering devices, the inspectors verified that drainage of the area was available, or that the cables were qualified for submerged conditions. The inspectors also reviewed the licensee's corrective action documents with respect to past submerged cable issues identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following underground manholes subject to flooding:

- Manhole 0B1, essential service water (SX) Tower South East Room;
- Manhole 0B2, SX Tower South West Room;
- Manhole 1H1, SX Field; and
- Manhole 2H2, SX Field.

This inspection constituted one underground vaults sample as defined in IP 71111.06-05.

b. Findings

No findings were identified.

1R08 Inservice Inspection Activities (71111.08P)

From September 19 through September 30, 2011, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the Unit 2 reactor coolant system (RCS), steam generator (SG) tubes, emergency feedwater systems, risk-significant piping and components, and containment systems.

The inspections described in Sections 1R08.1, 1R08.2, R08.3, 1R08.4, and 1R08.5 below count as one inspection sample as defined by IP 71111.08–05. Documents reviewed are listed in the Attachment.

.1 Piping Systems Inservice Inspection

a. Inspection Scope

The inspectors observed the following nondestructive examinations required by the American Society of Mechanical Engineers (ASME), Section XI, Code and/or 10 CFR 50.55a, to evaluate compliance with the ASME Code Section XI-applicable ASME Code Case and Section V requirements and if any indications were detected, to determine if these indications were dispositioned in accordance with the ASME Code or an NRC-approved alternative requirement.

- Ultrasonic Examination of the Safety Injection Line Weld (2SI08CA-4 FW-8); Report No. B2R16-UT-005;
- Ultrasonic Examination of the Safety Injection Line Weld (2SI08CA-4 FW-9), Report No. B2R16-UT-006;
- Ultrasonic Examination of the Safety Injection Line Weld (2SI08CA-4 FW-10), Report No. B2R16-UT-007;
- Ultrasonic Examination of the Chemical and Volume Control Line Weld (2CVB7A J17) Report No. B2R16-UT-018;
- Ultrasonic Examination of the Chemical and Volume Control Line Weld (2CVB7A J18); Report No. B2R16-UT-019;

- Liquid Penetrant Examination of the Chemical and Volume Control Line Weld (2CVB7A J16A); Report No. B2R16-PT-002;
- Radiographic Examination of the Safety Injection Line Weld (2SI08CB-4, FW 1); Report No. 2011-542;
- Radiographic Examination of the Safety Injection Line Weld (2SI08CB-4, FW 1, Repair 1); Report No. 2011-557;
- Ultrasonic Examination of the Feedwater Line Weld (2FW81BD-6, Weld 107); Report No. B2R16-UT-009;
- Ultrasonic Examination of the Feedwater Line Weld (2FW81BD-6, Weld 107); Report No. B2R16-UT-010;
- Ultrasonic Examination of the Feedwater Line Weld (2FW81BD-6, Weld 107); Report No. B2R16-UT-011; and
- Ultrasonic Examination of the Feedwater Line Weld (2FW81BD-6, Weld 107); Report No. B2R16-UT-012.

The inspectors reviewed the following examinations completed during the previous outage with relevant and/or recordable conditions and/or indications accepted for continued service to determine if acceptance was in accordance with the ASME Code Section XI or an NRC-approved alternative.

- Residual Heat Removal System (2RH02AA-8/C47) Liquid Penetrant Indication, Report Number B2R15-PT-010; and
- Safety Injection System (2SI03DA-2/W-08A) Liquid Penetrant Indication, Report Number B2R15-PT-004.

The inspectors reviewed the following pressure boundary welds completed for risk-significant systems during the Unit 2 refueling outage to determine if the licensee applied the pre-service non-destructive examinations and acceptance criteria required by the construction code, and NRC-approved Code Case N-416. Additionally, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to determine if the weld procedures were qualified in accordance with the requirements of construction code and the ASME Code Section IX.

- Welds (FW-6, 7. 8, 9, 10, 11, and 13) performed during the safety injection system piping/valve modification to add locked open valves in series with 2SI8801 A/B (WO 01430341-01); and
- Welds (2, 3, 4, 5, 6, and 7) performed during the replacement of the four Unit 2 reactor head vent solenoid valves (2RC014A/B/C/D) (WO 01279020-01).

b. Findings

No findings were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

For the Unit 2 reactor pressure vessel upper head, a volumetric (ultrasonic examination) and bare metal visual examination on all 79 upper head penetrations (1 vent line, 23 open housing penetrations, and 55 thermal sleeved penetrations) was required this outage pursuant to 10 CFR 50.55a(g)(6)(ii)(D).

The inspectors reviewed records of the bare metal visual examination conducted on the Unit 2 reactor vessel head penetrations to determine if the activities were conducted in accordance with the requirements of ASME Code Case N-729-1 and 10 CFR 50.55a(g)(6)(ii)(D). In particular, the inspectors confirmed that:

- the required visual examination scope/coverage was achieved and limitations (if applicable were recorded) in accordance with the licensee procedures
- the licensee criteria for visual examination quality and instructions for resolving interference and masking issues were adequate; and
- if indications of potential through-wall leakage were identified, the licensee entered the condition into the corrective action system and implemented appropriate corrective actions.

The inspectors observed and reviewed records of the volumetric (ultrasonic) examinations conducted on the Unit 2 reactor vessel upper head at penetrations 62, 64, 74, 76, and 78 to determine if the activities were conducted in accordance with the requirements of ASME Code Case N-729-1 and 10 CFR 50.55a(g)(6)(ii)(D). In particular, the inspectors confirmed that:

- the required examination scope (volumetric and surface coverage) was achieved and limitations (if applicable were recorded) in accordance with the licensee procedures;
- the ultrasonic examination equipment and procedures used were demonstrated by blind demonstration testing;
- if indications or defects were identified, the licensee documented the conditions in examination reports and/or entered this condition into the corrective action system and implemented appropriate corrective actions; and
- if indications were accepted for continued service, the licensee evaluation and acceptance criteria were in accordance with the ASME Section XI Code, 10 CFR 50.55a(g)(6)(ii)(D) or an NRC-approved alternative.

No welded repairs on the upper head penetrations were performed during the current outage.

b. Findings

No findings were identified.

.3 Boric Acid Corrosion Control

a. Inspection Scope

On September 19, 2011 the inspectors observed the licensee staff performing visual examinations of the Unit 2 RCS and emergency core cooling system within containment to determine if these visual examinations focused on locations where boric acid leaks can cause degradation of safety significant components.

The inspectors reviewed the following licensee evaluations of RCS components with boric acid deposits to determine if degraded components were documented in the corrective action program. The inspectors also evaluated corrective actions for any degraded RCS components to determine if they met the ASME Section XI Code.

- IR 1262152, Boron Identified On Pipe Cap/Valve 2CV204;
- IR 1232955, 2CS 049A Covered In Boric Acid; and
- IR 1260896, Inactive Boric Acid Leak On Valve Packing 2PS258.

The inspectors reviewed the following corrective actions related to evidence of boric acid leakage to determine if the corrective actions completed were consistent with the requirements of the ASME Code Section XI and 10 CFR Part 50, Appendix B, Criterion XVI.

- Inactive Minor Boric Acid Leak On 2SI8905D (AR 01220824); and
- Minor Inactive Boric Acid Leak On Valve 2SI8809B Packing (AR 01247989).

b. Findings

No findings were identified.

.4 Steam Generator Tube Inspection Activities

a. Inspection Scope

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

- In-situ SG tube pressure testing screening criteria used were consistent with those identified in the Electric Power Research Institute (EPRI) TR-107620, Steam Generator In-Situ Pressure Test Guidelines and that these criteria were properly applied to screen degraded SG tubes for in-situ pressure testing;
- the numbers and sizes of SG tube flaws/degradation identified was bounded by the licensee's previous outage Operational Assessment predictions;
- the SG tube ET examination scope and expansion criteria were sufficient to meet the Technical Specifications, and the EPRI TR-1003138, Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6;
- the SG tube ET examination scope included potential areas of tube degradation identified in prior outage SG tube inspections and/or as identified in NRC generic industry operating experience applicable to these SG tubes;
- the licensee identified new tube degradation mechanisms and implemented adequate extent of condition inspection scope and repairs for the new tube degradation mechanism;
- the licensee implemented repair methods which were consistent with the repair processes allowed in the plant TS requirements and to determine if qualified depth sizing methods were applied to degraded tubes accepted for continued service;
- the licensee implemented an inappropriate "plug on detection" tube repair threshold (e.g., no attempt at sizing of flaws to confirm tube integrity);
- the licensee primary-to-secondary leakage (e.g., SG tube leakage) was below 3 gallons-per-day or the detection threshold during the previous operating cycle;
- the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known and/or expected types of SG tube degradation in accordance with Appendix H, Performance Demonstration for

Eddy Current Examination, of EPRI TR-1003138, Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 6; and
- the licensee performed secondary side SG inspections for location and removal of foreign materials.

There was no in-situ pressure testing performed during this outage.

b. Findings

No findings were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI and SG related problems entered into the licensee's corrective action program and conducted interviews with licensee staff to determine if:

- the licensee had established an appropriate threshold for identifying ISI and SG related problems;
- the licensee had performed a root cause (if applicable) and taken appropriate corrective actions; and
- the licensee had evaluated operating experience and industry generic issues related to ISI and pressure boundary integrity.

The inspectors performed these reviews to evaluate 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.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On August 30, 2011, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;

- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and emergency plan actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator requalification program sample as defined in IP 71111.11.

b. <u>Findings</u>

No findings were identified.

1R12 <u>Maintenance Effectiveness</u> (71111.12)

.1 <u>Routine Quarterly Evaluations</u> (71111.12Q)

a. <u>Inspection Scope</u>

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- SX Cooling Tower Maintenance.

The inspectors reviewed events including those in which ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the Maintenance Rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2) or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

This inspection constituted one quarterly maintenance effectiveness sample as defined in IP 71111.12-05.

b. Findings

No findings were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- Risk Management Associated with SX Valve 2SX011 Replacement;
- Shutdown Safety Associated with Unit 2 Core Reload; and
- Shutdown Safety Associated with Unit 2 Cavity Drained.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

These maintenance risk assessments and emergent work control activities constituted three samples as defined in IP 71111.13-05.

b. Findings

Failure to Identify Elevated Risk Status

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” when licensee personnel removed the Unit 2 CC heat exchanger from service without entering a Yellow risk status and failed to perform required Risk Management Actions (RMAs).

Description: On September 13, 2011, while performing a routine verification of the licensee's risk status and RMAs, the inspectors observed that neither unit had entered a Yellow risk status even though the Unit 2 CC heat exchanger was out of service for a valve replacement. At approximately 2:08 a.m. of that day, a clearance order was placed to allow the safe removal of valve 2SX011. As a result, the Unit 2 CC heat exchanger became inoperable. Both Unit 1 and Unit 2 entered the appropriate 7-day Limiting Condition for Operation (LCO). Due to a cognitive personnel error in which the work cycle manager failed to enter the correct isolated valve in the risk profile for the work week, the licensee failed to identify that the placement of the clearance order would render the Unit 2 CC heat exchanger inoperable. In addition, the operating crew that placed the clearance order and the operating crew on the following shift failed to identify that the new temporary configuration placed both units in an elevated (Yellow) risk status in accordance with online risk management procedure.

Following questions by the inspectors, the licensee re-evaluated the online risk with the correct valve entered into the risk profile, which rendered the Unit 2 CC heat exchanger inoperable. As a result, the licensee entered a Yellow risk status at 5:25 p.m. for Unit 2 and 7:00 p.m. for Unit 1 in accordance with their online risk profile procedure. In addition, the licensee performed the required RMAs of protecting the Unit 0 CC heat exchanger, valve 2SX005, and valve 2SX007, from other work activities (no work activities had been performed on this equipment). These RMAs remained in effect for the remaining 2 days of work.

<u>Analysis</u>: The inspectors determined that the failure to control online risk in accordance with the online risk management procedure was a performance deficiency. The performance deficiency was determined to be more than minor because it was associated with the Human Performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This issue was also similar to Example 7.e in IMC 0612, Appendix E, "Examples of Minor Issues," in that a failure to perform an adequate risk assessment when required by 10 CFR 50.65(a)(4) is not minor if the overall elevated plant risk placed the plant into a higher risk category established by the licensee or would require, under plant procedures, RMAs.

The inspectors determined that the finding could be evaluated in accordance with IMC 0609, Appendix K, "Maintenance Risk Assessment and Risk Management Significance Determination Process." In accordance with IMC 0609, Appendix K, a Senior Reactor Analyst (SRA) contacted the licensee and the licensee re-performed the risk assessment that included the Unit 2 CC heat exchanger being unavailable; the omission of which rendered the original risk assessment inadequate. The licensee determined that the risk deficit for the unevaluated condition of the Unit 2 CC heat exchanger being unavailable for 14 hours and 16 minutes, or 0.6 days, was less than 1E-8.

The SRA performed an independent analysis of the risk deficit for the unevaluated condition of the Unit 2 CC heat exchanger being unavailable. An exposure time of 0.6 days was used due to the clearance order that made the Unit 2 CC heat exchanger unavailable being placed on September 13, 2011, at 2:08 a.m. and a log entry at 4:24 p.m. on September 13, 2011, recording that the unavailability of the Unit 2 CC heat exchanger was not evaluated.

The Byron Standardized Plant Analysis Risk (SPAR) model Version 8.18 and SAPHIRE model Version 8.0.7.17 were used to calculate an Incremental Core Damage Probability Deficit (ICDPD) for the condition of the Unit 2 CC heat exchanger being unavailable for 0.6 days. The result was an ICDPD of less than 5E-7. The dominant sequence was a medium loss of coolant accident initiating event with a failure of low pressure recirculation. In accordance with Inspection Manual Chapter (IMC) 0609, Appendix K, and because the calculated ICDPD was not greater than 1E-6, the finding was determined to be of very low safety significance (Green).

This finding had a cross-cutting aspect in the Work Control component of the Human Performance cross-cutting area [H.3.(a)] because the licensee failed to appropriately incorporate risk insights when the Unit 2 CC heat exchanger was removed from service.

Enforcement: 10 CFR 50.65(a)(4) requires, in part, that the licensee shall assess and manage the increase in risk that may result from proposed maintenance activities. Contrary to this requirement, for approximately 0.6 days on September 13, 2011, the licensee's risk assessment did not accurately reflect the increase in online risk associated with the removal from service of the Unit 2 CC heat exchanger for proposed maintenance and the licensee failed to assess and manage the increase risk from the proposed maintenance through the implementation of required Risk Management Actions. Because of the very low safety significance of this finding and because the issue was entered into the licensee's CAP as IR 1262639, this violation is being treated as a NCV consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000455/2011004-01, Failure to Identify Elevated Risk Status).

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Prompt Operability Decision Associated with Unit 1 Train A Diesel Generator Due to Variance with Testing Methodology as Outlined in Regulatory Guide 1.9;
- Unit 2 Train A Diesel Generator Ventilation Vent Fan Failure to Start;
- High Energy Line Break Prompt Operability Decision; and
- Degraded Concrete Found in SX Cooling Tower Cell 0E.

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and UFSAR to the licensee’s evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sample of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment.

This operability inspection constituted four samples as defined in IP 71111.15-05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following post maintenance testing activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- Unit 2 Train B Diesel Generator Following Jacket Water Temperature Switch Replacement;
- Unit 2 Train B Diesel Generator Following Ventilation Fan Relay Modification;
- Unit 1 Train B Battery Charger Operability Test After Returning to Service;
- Unit 2 Containment Polar Crane Following Gearbox Replacement; and
- Unit 2 Train B Safety Injection Valve 2SI8811B Following Modifications associated with Multiple Spurious Operations.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment.

This inspection constituted five post maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for Unit 2 Refueling Outage (RFO) B2R16, which started September 18, 2011, and at the end of the inspection period was ongoing to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the RFO, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below. Documents reviewed during the inspection are listed in the Attachment.

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the OSP for key safety functions and compliance with the applicable TS when taking equipment out of service.
- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing.
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error.
- Controls over the status and configuration of electrical systems to ensure that TS and OSP requirements were met, and controls over switchyard activities.
- Monitoring of decay heat removal processes, systems, and components.
- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system.
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.
- Controls over activities that could affect reactivity.
- Maintenance of secondary containment as required by TS.
- Refueling activities, including fuel handling and sipping to detect fuel assembly leakage.
- Licensee identification and resolution of problems related to RO activities.

This inspection constituted one partially completed RFO sample as defined in IP 71111.20-05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- Unit 2 Train A Diesel Generator Monthly Surveillance;
- Test of the Master Fire Protection CO_2 Valves;
- Unit 2 Train A DC Bus 211 125V Battery Charger Operability Test;
- Undervoltage Simulated Start of the Unit 2 Train A AF Pump;
- Unit 1 Comprehensive Inservice Testing (IST) Requirements for the Unit 1 Train A Containment Spray Pump; and
- Unit 2 Local Leak Rate Testing for Containment Penetration P-70.

The inspectors observed in-plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as left setpoints were within required ranges; and the calibration frequency were in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, ASMEs code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;

- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment.

This inspection constituted five routine surveillance testing samples and one inservice testing sample, as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Training Observation

a. Inspection Scope

The inspector observed a simulator training evolution for licensed operators on August 30, 2011, which required Emergency Plan implementation by a licensee operations crew. This evolution was planned to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that the licensee evaluators noted the same issues and entered them into the CAP. As part of the inspection, the inspectors reviewed the scenario package and other documents listed in the Attachment.

This inspection of the licensee's training evolution with emergency preparedness drill aspects constituted one sample as defined in IP 71114.06-05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2RS2 Occupational As-Low-As-Is-Reasonably-Achievable Planning and Controls (71124.02)

This inspection constituted one complete sample as defined in IP 71124.02-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

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

The inspectors reviewed the site-specific trends in collective exposures using NUREG-0713, "Occupational Radiation Exposure at Commercial Nuclear Power Reactors and Other Facilities," and plant historical data and source term (average contact dose rate with reactor coolant piping) measurements using Electric Power Research Institute (EPRI) TR-108737, "BWR Iron Control Monitoring Interim Report," issued December 1998, and/or plant historical data, when available.

The inspectors reviewed site-specific procedures associated with maintaining occupational exposures as-low-as-is-reasonably-achievable (ALARA), which included a review of processes used to estimate and track exposures from specific work activities.

b. Findings

No findings were identified.

.2 Radiological Work Planning (02.02)

a. Inspection Scope

The inspectors selected the following work activities of the highest exposure significance.

- Radiological Work Planning (RWP) 100012353; B2R16 Rx Head – Disassemble and Reassemble – All Activities;
- RWP 10012372; Outage Scaffolds;
- RWP 10012384; B2R16 Steam Generator Manway/Diaphragm Removal/Installation; and
- RWP 10012383; SG Platform & Bullpen Set-Up/Tear Down and Decon Activities.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements. The inspectors determined whether the licensee reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

The inspectors assessed whether the licensee's planning identified appropriate dose mitigation features; considered alternate mitigation features; and defined reasonable dose goals. The inspectors evaluated whether the licensee's ALARA assessment had taken into account decreased worker efficiency from use of respiratory protective devices and/or heat stress mitigation equipment (e.g., ice vests). The inspectors determined whether the licensee's work planning considered the use of remote technologies (e.g., teledosimetry, remote visual monitoring, and robotics) as a means to reduce dose and the use of dose reduction insights from industry operating experience and plant-specific lessons learned. The inspectors assessed the integration of ALARA requirements into work procedure and radiation work permit documents.

The inspectors compared the results achieved (dose rate reductions, person-rem used) with the intended dose established in the licensee's ALARA planning for these work activities. The inspectors compared the person-hour estimates provided by maintenance planning and other groups to the radiation protection group with the actual work activity time requirements, and evaluated the accuracy of these time estimates. The inspectors assessed the reasons (e.g., failure to adequately plan the activity, failure to provide sufficient work controls) for any inconsistencies between intended and actual work activity doses.

The inspectors determined whether post-job reviews were conducted and if identified problems were entered into the licensee's CAP.

b. Findings

No findings were identified.

3. Verification of Dose Estimates and Exposure Tracking Systems (02.03)

a. Inspection Scope

The inspectors reviewed the assumptions and basis (including dose rate and person-hour estimates) for the current annual collective exposure estimate for reasonable accuracy for select ALARA work packages. The inspectors reviewed applicable procedures to determine the methodology for estimating exposures from specific work activities and the intended dose outcome.

The inspectors evaluated whether the licensee had established measures to track, trend, and if necessary, to reduce occupational doses for ongoing work activities. The inspectors assessed whether trigger points or criteria were established to prompt additional reviews and/or additional ALARA planning and controls.

The inspectors evaluated the licensee's method of adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered. The inspectors assessed whether adjustments to exposure estimates (intended dose) were based on sound radiation protection and ALARA principles or if they were just adjusted to account for failures to control the work. The inspectors evaluated whether the frequency of these adjustments called into question the adequacy of the original ALARA planning process.

b. Findings

No findings were identified.

.4 Source Term Reduction and Control (02.04)

a. Inspection Scope

The inspectors used licensee records to determine the historical trends and current status of significant tracked plant source terms known to contribute to elevated facility aggregate exposure. The inspectors assessed whether the licensee had made allowances or developed contingency plans for expected changes in the source term as the result of changes in plant fuel performance issues or changes in plant primary chemistry.

b. Findings

No findings were identified.

.5 Radiation Worker Performance (02.05)

a. Inspection Scope

The inspectors observed radiation worker and radiation protection technician performance during work activities being performed in radiation areas, airborne radioactivity areas, or high radiation areas. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice (e.g., workers were familiar with the work activity scope and tools to be used, workers used ALARA low-dose waiting areas) and whether there were any procedure compliance issues (e.g., workers not complying with work activity controls). The inspectors observed radiation worker performance to assess whether the training and skill level was sufficient with respect to the radiological hazards and the work involved.

b. Findings

No findings were identified.

.6 Problem Identification and Resolution (02.06)

a. Inspection Scope

The inspectors evaluated whether problems associated with ALARA planning and controls were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's corrective action program.

b. Findings

No findings were identified.

2. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

4OA1 Performance Indicator Verification (71151)

.1 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the Unit 1 and Unit 2 RCS Leakage Performance Indicator (PI) for the period from the 3rd quarter 2010 through the 2nd quarter 2011. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, was used. The inspectors reviewed the licensee's operator logs, RCS leakage tracking data, issue reports, event reports and NRC Integrated Inspection Reports for the period of June 2010 through June 2011 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two RCS leakage samples as defined in IP 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: the complete and accurate identification of the problem; that timeliness was commensurate with the safety significance; that evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrence reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the attached List of Documents Reviewed.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

.3 Selected Issue Follow-Up Inspection: Licensee Issue Report on Auxiliary Feedwater System Crosstie Modification

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting operating experience from another licensee's facility regarding a shared unit service water system.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05.

b. Findings

Installation of a Pump Discharge Crosstie Between Unit 1 and Unit 2 Motor Driven Auxiliary Feedwater Pumps Without NRC Approval

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated Severity Level IV NCV of 10 CFR 50.59, "Changes, Tests, and Experiments," when licensee personnel failed to obtain a license amendment prior to implementing a proposed change to the plant that resulted in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system or component important to safety previously evaluated in the UFSAR. Specifically, the licensee performed a modification to the facility that permitted the Unit 1 and Unit 2 "A" AF trains to be shared between units and the 10 CFR 50.59 evaluation that was performed reached the erroneous conclusion that prior NRC approval was not required.

Description: Engineering Change 362168, Revision 0, dated August 7, 2008, approved the installation of a modification to add a crosstie line between the Unit 1 and Unit 2 "A" AF trains to permit the sharing of the Unit 1 and Unit "A" AF trains between the Units. The inspectors selected an IR for a more detailed review that questioned whether this plant modification required NRC review and approval prior to implementation. Issue Report 1232153 referenced operating experience (OpEx) from another licensee facility which pre-dated the installation of the crosstie modification and discussed an NRC-identified violation on the sharing of a service water system between Units (reference NRC Integrated Inspection Report 05000369/370-2011002, issued May 6, 2011). Issue Report 1232153 stated, in part, that "The concerns raised by the NRC [in the referenced NRC inspection report] which resulted in the NCV appear to be consistent with the Byron/Braidwood modifications and subsequent incorporation into station procedures, A-Train AF crosstie line modifications." On June 28, 2011, the licensee's conclusion in Issue Report 1232153 stated that "…the McGuire finding does not apply to the AF crosstie modification at B/B [Byron and Braidwood]."

After the licensee concluded the OpEx did not apply to the AF crosstie modification, the inspectors began reviewing background material related to the AF crosstie modification. The inspectors determined that the licensee's AF crosstie modification created a shared system that had not previously existed and was not described in the UFSAR or other licensing basis documents. In addition, the inspectors determined that the processes and procedures for placing the opposite unit's "A" Train of AF in service for the accident unit resulted in the non-accident unit losing the redundancy and diversity of the AF system that would otherwise have been available if the Unit 1 and Unit 2 "A" AF trains were not crosstied. The crosstie piping was isolated with the use of two manual closed and locked isolation valves and was controlled by the licensee's Emergency Operating Procedures (EOPs). With the use of two manually closed isolation valves separating the two unit's "A" train AF pumps from each other, the crosstie would only be open during the implementation of certain portions of Byron EOP 1/2BFR H.1, "Loss of Secondary Heat Sink."

In the 10 CFR 50.59 evaluation for the AF crosstie modification and associated EOP 1/2BFR H.1, the licensee determined that the modification and the procedure change did not result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system and component important to safety previously evaluated in the UFSAR. However, based on the loss of redundancy and diversity when the crosstie was implemented, the inspectors determined that the modification and procedure change did, in fact, result in more than a minimal increase in the likelihood of occurrence of a malfunction of the AF system of the donor unit. Therefore, prior NRC approval was required for the licensee to utilize the crosstie, but had not been requested.

The inspectors determined that this issue did not affect the operability of the AF system because the licensee required that prior to use of the crosstie, both of the non-accident unit AF trains be operable. This would have ensured that at least one train of the AF system was available for use on the non-accident unit. The AF crosstie modification had not been used by the licensee as it would have required a beyond design basis event (loss of both trains of AF on one unit) with entry into EOP 1/2BFR H.1, and no such event had occurred.

In addition to initiating IR 1257908, as part of their corrective actions the licensee issued Standing Order 11-050, which had the effect of modifying EOP 1/2BFR H.1. Prior to executing the step of this EOP which prescribed the use of the crosstie modification, Shift Manager approval and invocation of 10 CFR 50.54(x) were required. The licensee planned to submit a License Amendment Request (LAR) to the NRC for this design change by mid-December 2011. In addition, at the end of the inspection period, the licensee was in the process of revising EOP 1/2BFR H.1 to require the use of 10 CFR 50.54(x) prior to making use of the crosstie modification. This procedure revision was expected to be completed by October 1, 2011.

Analysis: The inspectors determined that the failure to perform an adequate 10 CFR 50.59 evaluation and obtain a license amendment prior to implementing the portion of EOP1/2BFR H.1 which utilized the crosstie between the Unit 1 and Unit 2 "A" AF pumps was a performance deficiency warranting a significance evaluation. Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors evaluated the issue using the traditional enforcement process and assessed the significance of the underlying issue using the SDP.

Violations of 10 CFR 50.59 are dispositioned using the traditional enforcement process instead of the SDP because they are considered to be violations that potentially impede or impact the regulatory process. However, if possible, the underlying technical issue is evaluated under the SDP to determine the severity of the violation. In this case, the inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Tables 4a, for the Mitigating Systems Cornerstone. The inspectors answered "Yes" to Question 1 of the Mitigating Systems Cornerstone column of the Phase 1 worksheet because the inspectors concluded that this was a change confirmed not to result in the loss of operability. Based upon this Phase 1 screening, the inspectors concluded that the finding was of very low safety significance (Green).

Therefore, in accordance with Section 6.1.d.2 of the NRC Enforcement Policy, this violation was categorized as Severity Level IV because the resulting changes were evaluated by the SDP as having very low safety significance (Green).

This finding had a cross-cutting aspect in the Operating Experience component of the Problem Identification and Resolution (PI&R) cross-cutting area [P.2.(b)] because the licensee failed to make adequate use of known industry operating experience in the evaluation of a modification.

<u>Enforcement</u>: 10 CFR Part 50.59, "Changes, Tests, and Experiments," Section (c)(2)(ii), requires, in part, that the licensee obtain a license amendment prior to implementing a proposed change to the plant that would result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system or component important to safety previously evaluated in the UFSAR.

Contrary to the above, on August 7, 2008, the licensee implemented Engineering Change 362168 and EOP 1/2BFR H.1, which resulted in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system or component important to safety previously evaluated in the UFSAR, without obtaining a required license amendment. Specifically, Engineering Change 362168, Revision 0, dated August 7, 2008, approved a modification to add a crosstie line between the Unit 1 and Unit 2 "A" AF trains to permit the sharing of the Unit 1 and Unit "A" AF trains between the Units and the modification was subsequently installed. The crosstie piping was isolated with the use of two manual closed and locked isolation valves and was controlled by EOP 1/2BFR H.1, "Loss of Secondary Heat Sink." In accordance with the Enforcement Policy, the violation was classified as a Severity Level IV violation because the underlying technical issue was of very low safety significance. Because this violation was of very low safety significance, was not repetitive or willful, and was entered into the licensee's CAP as IR 1257908, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000454/2011004-02; 05000455/2011004-02, Modification of the Auxiliary Feedwater System Without Prior NRC Approval)**

As stated above, the underlying technical issue was evaluated separately from the traditional enforcement violation and therefore the finding was assigned a separate tracking number. **(FIN 05000454/2011004-03; 05000455/2011004-03, Modification of the Auxiliary Feedwater System)**

.4 Selected Issue Follow-Up Inspection: Generic Letter 89-13 Commitments

a. Inspection Scope

During a review of items entered in the licensee’s CAP, the inspectors recognized a corrective action item documenting a request for a change to a surveillance frequency associated with activities supporting Generic Letter 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” commitments.

The inspectors reviewed the licensee's corrective actions for the issues identified to determine whether: (1) the problems were accurately identified; (2) the causes were adequately ascertained; (3) extent of condition and generic implications were appropriately addressed; (4) previous occurrences were considered; and (5) corrective actions proposed and/or implemented were appropriately focused to address the problems and were commensurate with the safety significance of the issues. Documents reviewed are listed in the Attachment.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05.

b. Findings

No findings were identified.

.5 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee’s CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors’ review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors’ review nominally considered the 6 month period of January 2011 through June 2011, although some examples expanded beyond those dates where an increase in the scope of the trend was warranted.

The review also included issues documented outside the scope of the CAP, such as major equipment problem lists, repetitive and/or reworks maintenance lists, departmental problem and/or challenge lists, system health reports, quality assurance audit and surveillance reports, self assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee’s CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee’s trending reports were reviewed for adequacy.

This review constituted a single semi-annual trend inspection sample as defined in IP 71152-05.

b. Findings

No findings were identified.

4OA3 Follow-up of Events and Notices of Enforcement Discretion (71153)

.1 (Updated) Licensee Event Report 05000454/2010001-00; 05000455/2010001-00: Technical Specification Allowed Outage Time Extension Request for Component Cooling Water System, Contained Inaccurate Information That Significantly Impacted the Technical Justification

The licensee submitted this Licensee Event Report (LER) on January 11, 2011 after identifying that a 1987 license submittal contained inaccurate information. Based on Component Cooling Water (CC) system design discrepancies that were known to exist since the mid-1980's, an incorrect modeling of the CC system was used in an early Probabilistic Risk Assessment (PRA). The PRA was one of the main justifications utilized by the licensee in a request to extend the TS LCO Allowed Outage Time (AOT) for the CC system.

Administrative controls were implemented by the licensee as short-term corrective actions. These controls consisted of reducing the CC system AOT from 7 days to 72 hours, reducing the AOT for an inoperable residual heat removal train from 7 days to 72 hours, and prohibiting the Unit Common CC pump from being aligned as either unit's "B" train of CC. Additional corrective actions include proposed modifications to restore compliance with the current licensing basis. Pending partial or complete implementation of the proposed modifications, this LER will remain open. After discussions with the Office of Enforcement, there was no violation of NRC requirements associated with the licensee's submittal of inaccurate information in the 1987 TS change request as the issue predates the effective date of 10 CFR 50.9 (EA-11-167).

Licensee Event Report 05000454/2010001-00; 05000455/2010001-00 remains open.

4OA5 Other Activities

.1 (Closed) Unresolved Item 05000454/2011015-01; 05000455/2011015-01; Design of Auxiliary Feedwater System Included Voids in Safety-Related Alternate Suction Flow Paths

This issue was initially reported by the licensee in LER 2011-003-00. Concerns with current operability were the subject of a Special Inspection and have been assessed by the NRC in Inspection Report 0500454/2011015; 0500455/2011015. This report will focus on the Unresolved Item opened during the Special Inspection, specifically, the issue of past operability. The inspectors reviewed this issue and identified a violation of NRC requirements. This issue is discussed below. This Unresolved Item is closed.

a. Inspection Scope

The inspectors reviewed design and licensing documentation to determine the circumstances surrounding the acceptance of the AF system design and interfaces with the SX system. Vendor system description documentation dating to the time of construction indicated that the AF and SX systems at Braidwood and Byron were designed to include a voided section in the SX supply piping to the AF system. The purpose of this voided section was to prevent SX water from leaking by valve seats and into the steam generators, which would have an adverse effect on steam generator water chemistry. The inspectors were unable to determine details about initial design review or acceptance of the voids by the licensee, but concluded that the inclusion of voids in the SX supply piping to the AF system was known to the licensee at the time of construction.

b. Findings

Design of Auxiliary Feedwater System Included Voids in Safety-Related Alternate Suction Flow Paths

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors when licensee personnel failed to properly analyze the configuration of the SX connections to the AF pumps. Specifically, a section of the piping was intentionally maintained empty (voided), but had not been previously analyzed. This condition existed since initial plant construction.

Description: While observing a routine surveillance of the Unit 2 Train B AF pump, the inspector identified that a section of pipe was voided. This section of pipe was maintained empty per the plant design to allow for the detection of leakage past either of two isolation valves, valve 2AF006B and valve 2AF0017B. This issue also applied to Unit 2 Train A and both Unit 1 AF trains.

Conversations with the system engineer revealed that the licensee had investigated this issue in 1993. In correspondence between the licensee and the pump vendor, dated May 28, 1993, the vendor indicated that there would be no loss of net positive suction head due to the SX pressure at the suction of the AF pump being approximately 80 pounds per square inch gauge (psig). The vendor stated that a 1.5 cubic foot slug of air at 80 psig would not damage the pump as it passed through it. The correspondence made no mention of system performance or an assessment of system impacts. The correspondence did make reference to a position that was established on August 27, 1987, for a different licensee with unknown equipment and with an unknown configuration. That position concluded that 1.5 cubic feet of air at 80 psig would not damage the AF pump. The reference neither cited an analysis, calculation, or test as the basis for these conclusions. Licensee staff believed that tests were performed around the 1987 timeframe, but were unable to provide any information regarding the purpose of the tests, the configuration of equipment during the tests, type and qualification of equipment used, or copies of test reports and results. The licensee contacted the pump vendor who was also unable to locate any documentation to support the 1993 reference or the 1987 reference. In summary, the licensee failed to locate any calculations or test reports produced during original plant construction and installation onsite or evidence of analysis or testing prior to construction and installation onsite. The licensee entered this issue into the CAP as IR 1172938 and completed filling all of the voided pipe sections on February 15, 2011.

In order to address the lack of an analysis, test, or record, the licensee elected to perform testing of equipment of a similar type and configuration. The inspectors reviewed the new AF test methodology and results. The inspectors concluded that the test provided reasonable assurance the AF pumps would not have been adversely affected by the presence of the voids previously located between isolation valves 1/2AF006A/B and 1/2AF017A/B. Therefore, the pumps were and remained operable regarding this issue. However, the test did not provide an adequate degree of certainty to be used for either design purposes nor to bound voids that could potentially be identified in the future under different circumstances. Specifically, the inspectors noted a number of limitations of the test including the following:

- Test methodology MPR 3575, “AF Pump Test Methodology,” stated “Each test shall be repeated thrice to show repeatability.” However, the actual test was not repeated for each test case. Therefore, the uncertainty associated with the test data could not be established for a number of the test cases.

- Test methodology MPR 3575 stated “After testing is complete, the test pump will be disassembled and inspected to determine its condition.” The intent was to determine if the AF pumps had received any damage that would have prevented them from meeting their mission time. However, the licensee did not disassemble and inspect the test pump. The only rotor-dynamic parameters considered during the test were vibration and seal temperature, which were not sufficient to determine the axial and torsional impact of the void. However, because the pump was able to run for multiple short periods of time with multiple voids, there was reasonable assurance the pumps would have remained operable. That is, the pump likely would not have experienced adverse rotor-dynamic effects due to one void followed by a continuous operation for a relatively longer period of time, which was the condition of concern.

- The test data reported in MPR 3602, “Braidwood and Byron AF Pump Air Ingestion Test,” indicated that pump performance degraded significantly for some test cases as the void passed through the pump and the head was quickly re- developed once the void exited the pump. However, the test did not directly simulate the effect of SG back pressure. Specifically, the SGs were at a relatively high pressure of about 1000 pounds per square inch absolute (psia). The pump’s discharge check valve would close if its discharge pressure fell below that value. Some test cases indicated that the discharge pressure would have significantly decreased below the SG back pressure value. For past operability purposes, it appeared the void self-vented due to the piping configuration and SX system pressure. However, based on the testing methodology, it was not clear whether this would occur under all circumstances.

<u>Analysis</u>: The inspectors determined that the configuration of the SX connections to the AF pump was not verified analytically or by testing, which was contrary to design requirements and was a performance deficiency.

The finding was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attribute of Design Control and affected the cornerstone objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the unverified configuration might have rendered each of the AF pumps inoperable.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of Findings,” Table 4a, for the Mitigating Systems Cornerstone. The inspectors answered “Yes” to Question 1 of the Mitigating Systems Cornerstone column of the Phase 1 worksheet because the inspectors concluded that the finding did not to result in a loss of operability. This conclusion was reached after reviewing tests performed by the licensee. The tests demonstrated there was reasonable assurance that the AF system would perform its safety function under the installed configuration. Based upon this Phase 1 screening, the inspectors concluded that the finding was of very low safety significance (Green). Additionally, the licensee filled the voided sections of pipe, restoring compliance with the licensed design basis.

Due to the age of this issue, it was not reflective of current licensee performance and therefore the inspectors did not assign a cross-cutting aspect to this finding.

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures be provide for verifying the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Where a test program is used to verify the adequacy of a specific design feature in lieu of other verifying or checking processes, it shall include suitable qualifications testing of a prototype unit under the most adverse design conditions. Byron UFSAR, Section 3.2, "Classification of Structures, Components, and Systems," identified that Safety Category I Systems are intended to meet the requirements of 10 CFR 50, Appendix B. Table 3.2-1 identified the AF pumps as Safety Category I equipment.

Contrary to the above, prior to February 15, 2011, the licensee failed to establish measures to assure the adequacy of design, by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Specifically, the licensee failed to perform design reviews, calculations or suitable tests to verify the adequacy of the design of the installed AF configuration, including voided pipe sections. Because this issue was of very low safety significance (Green) and was entered into the licensee's CAP as 1172938, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000454/2011004-04; 05000455/-2011004-04, Design of Auxiliary Feedwater System Included Voids in Safety-Related Alternate Suction Flow Paths)**

4OA6 Management Meetings

.1 Exit Meeting Summary

On October 13, 2011, the inspectors presented the inspection results to Mr. B. Adams, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The results of the Inservice Inspection with the Site Vice President, Mr. T. Tulon, on September 30, 2011.
- The results of an Occupational ALARA Planning and Controls Inspection with the Site Vice President, Mr. T. Tulon, on September 30, 2011.

The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Tulon, Site Vice President
B. Adams, Plant Manager
B. Youman, Operations Manager
J. Feimster, Design Engineering Manager
D. Damptz, Acting Maintenance Director
S. Swanson, Nuclear Oversight Manager
R. Gayheart, Training Director
B. Barton, Radiation Protection Manager
K. Anderson, Acting Radiation Protection Manager
A. Creamean, Chemistry Manager
D. Gudger, Regulatory Assurance Manager

Nuclear Regulatory Commission

E. Duncan, Chief, Branch 3, Division of Reactor Projects

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000455/2011004-01	NCV	Failure to Identify Elevated Risk Status (Section 1R13)
05000454/2011004-02; 05000455/2011004-02	NCV	Modification of the Auxiliary Feedwater System Without Prior NRC Approval (Section 4OA2.3)
05000454/2011004-03; 05000455/2011004-03	FIN	Modification of the Auxiliary Feedwater System (Section 4OA2.3)
05000454/2011004-04; 05000455/2011004-04	NCV	Design of Auxiliary Feedwater System Included Voids in Safety-Related Alternate Suction Flow Paths (Section 4OA5)

Closed

05000455/2011004-01	NCV	Failure to Identify Elevated Risk Status (Section 1R13)
05000454/2011004-02; 05000455/2011004-02	NCV	Modification of the Auxiliary Feedwater System Without Prior NRC Approval (Section 4OA2.3)
05000454/2011004-03; 05000455/2011004-03	FIN	Modification of the Auxiliary Feedwater System (Section 4OA2.3)
05000454/2011004-04; 05000455/2011004-04	NCV	Design of Auxiliary Feedwater System Included Voids in Safety-Related Alternate Suction Flow Paths (Section 4OA5.1)
05000454/2011015-01; 05000455/2011015-01	URI	Design of Auxiliary Feedwater System Included Voids in Safety-Related Alternate Suction Flow Paths (Section 4OA5.1)

Discussed

05000454/2010-001-0 05000455/2010-001-0	LER	Technical Specification Allowed Outage Time Extension Request for Component Cooling Water System, Contained Inaccurate Information That Significantly Impacted the Technical Justification (Section 4OA3)

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.

Section 1R01: Adverse Weather Protection

- IR 1265934; Winter Readiness Challenge – No CST Heaters Available, September 21, 2011

Section 1R04: Equipment Alignment (Quarterly)

- DC PN 212; Building AB2, 451’ Elevation
- 212 Battery Charger AC Breaker
- 212 Battery Charger DC Breaker
- 125V DC Feed From Battery Charger 212 2DC04E
- Bus Tie Breaker to 125V DC Bus 112
- 2IP06E IP Inverter 212
- 2AP06EE Cont PWR Main-SWGR 242
- 2AP12EA Cont PWR Main-Bus 232X
- 2AP98EA Cont PWR Main-Bus 232Z
- 2RD05E Reactor Trip SWGR
- 2PM11J MCB Containment Isolation PNL DIV 22
- 2PL08J 2B DG Panel Cont PWR Breaker #1
- 2AP74EE Cont PWR Main-SWGR 256-RCP 2B
- 2AP04EC Cont PWR Main-SWGR 258-RCP 2C
- 2PL08J DG 2B Field Flashing
- 2PL05J Remote SD Panel AF, MSIV, B&C PORVs
- 2IP08E 1P Inverter 214
- 2DC11K ESF DC Fuse Panel
- 2AP06EE Cont PWR RES-SWGR 242
- 2AP12EA Cont PWR RES-BUS 232X
- 2AP98EA Cont PWR RES-BUS 232Z
- Feed to Non-ESF BUS 214 Fuses
- 6E-2-4010D; Revision K, Key Diagram 125V DC ESF Distribution Center
- DC Battery & Distribution System Train B Electrical Lineup – Unit 2
- 6E-2-4002F, Rev F, Single Line Diagram 120V AC ESF Instrument Inverter Bus 212
- BOP AF-M2A; Auxiliary Feedwater System Train A Valve Lineup, Revision 4
- BOP AF-E2A; Auxiliary Feedwater Unit 2 Train A Electrical Lineup, Revision 1

Section 1R04: Complete System Walkdown (Semi-Annual)

- Drawing M-136, Diagram of Safety Injection; Sheet 1, Revision AY
- Drawing M-136, Diagram of Safety Injection; Sheet 2, Revision AC
- Drawing M-136, Diagram of Safety Injection; Sheet 3, Revision AO
- Drawing M-136, Diagram of Safety Injection; Sheet 4, Revision AK
- Drawing M-136, Diagram of Safety Injection; Sheet 5, Revision N

- Drawing M-136, Diagram of Safety Injection; Sheet 6, Revision AJ
- BOP SI-E2B, Safety Injection System Train B Electrical Lineup, Revision 002
- BOP SI-M2B, Safety Injection System Train B Valve Lineup, Revision 002

Section 1R05: Fire Protection (Quarterly)

- Auxiliary Building 451'-0 Elevation Division 21 Miscellaneous Electrical Equipment and Battery Room
- Byron Station Pre-Fire Plan; Turbine Building 369'-0" Elevation Unit 2 Turbine Building Basement – North

Section 1R08: Inservice Inspection Activities

- ER-AA-330-009; ASME Section XI Repair Replacement Plan; Revision 6
- ER-AP-331; Boric Acid Corrosion Control Program; Revision 5
- ER-AP-331-1001; Boric Acid Corrosion Control (BACC) Inspection
- Locations, Implementation and Inspection Guidelines; Revision 5
- IR 01269906; Enhancement to Procedure Er-AA-335-1008; September 29, 2011
- IR 01268780; Reactor Vessel Head Penetration 76 and 78; September 27, 2011
- IR 01268131; Low Level Tube Denting In the 2B SG; September 26, 2011
- IR 01268433; RT Results of Field Weld No. 1 – Unsat; September 26, 2011
- EC 0000385032; B2R16 SG Degradation Assessment; September 22, 2011
- EC 0000380368; Byron Unit 2 B2R15 Steam Generator Condition Monitoring/Operational Assessment; July 22, 2010
- ER-AA-335-005; Radiographic Examination; Revision 4
- ER-AP-331-1002; Boric Acid Corrosion Control Program Identification, Screening and Evaluation; Revision 6
- ER-AP-331-1003; RCS Leakage Monitoring and Action Plan; Revision 4
- ER-AP-331-1004; Boric Acid Corrosion Control (BACC) Training and Qualification Revision 4
- ER-AP-335-001; Bare Metal Visual Examination for Alloy 600/82/182 Materials; Revision 1
- ER-AP-420-007; Byron/Braidwood Unit 2: Steam Generator Secondary Side Visual Surveillance Activities; Revision 6
- EXE-UT-350; Procedure for Acquiring Material Thickness and Weld Contours; Revision 2
- EXE-PDI-UT-1; Ultrasonic Examination of Ferritic Pipe Welds in Accordance with PDI-UT-1; Revision 6
- EXE-PDI-UT-2; Ultrasonic Examination of Austenitic Piping Welds in Accordance With PDI-UT-2; Revision 6
- ER-AA-335-002; Liquid Penetrant Examination; Revision 5
- ER-AA-335-1008; Code Acceptance and Recording Criteria for Nondestructive (NDE) Surface Examination; Revision 2
- Work Order 01341478; U2 RPV Head Bare Metal Visual Examination (BMV); August 8, 2011
- WPS 8-8-GTSM; ASME Welding Procedure Specification Record; Revision 2
- WDI-STD-1040; Procedure for Ultrasonic Examination of Reactor Vessel Head Penetrations; Revision 7
- WDI-STD-1041; Reactor Vessel Head Penetration Ultrasonic Examination Analysis; Revision 5
- EC 380368; Byron Unit 2 B2R15 Steam Generator Condition Monitoring Operational Assessment Report; Revision 0
- EC 385032; B2R16 Steam Generator Degradation Assessment; Revision 1

Section 1R12: Maintenance Effectiveness (Quarterly)

- IR 894592; Concrete Crack and Void in 0B SXCT, March 18, 2009
- IR 911028; Concrete Expansion Anchors (CEA) Not Enough Depth in Concrete, April 23, 2009
- IR 1042907; Concrete Fill Support Beams – B Cell SXCT, March 15, 2010
- IR 1095517; 1'6" x 1' Piece of Concrete Broken Off of 0SX163A Basin, July 29, 2010
- IR 1127719; SX CT D Cell – Minor Concrete Repair, October 18, 2010
- IR 1157747; Concrete Joint Leaks During 0B SX Basin M/U, January 02, 2011
- IR 1211373; SXCT – F Cell Concrete Inspection, May 03, 2011
- IR 1214661; SXCT – A Cell Concrete Inspection, May 11, 2011
- IR 1257349; 0E SXCT Concrete Inspection, August 30, 2011
- IR 0111838; Void Discovered in SX Cooling Tower During Repairs, June 13, 2002
- IR 0227277; Void Identified in SX Cooling Tower Fill Support Beam, June 9, 2004
- System health Reports for Essential Service Water, 2nd Quarter 2011

Section 1R13: Maintenance Risk Assessments and Emergent Work Control (Quarterly)

- OU-AP-104; Shutdown Safety Equipment Status Checklist, Revision 16
- 2A RH Train; Protected Equipment Tracking Log, September 30, 2011
- 2A CV Train; Protected Equipment Tracking Log, September 30, 2011
- Protected Equipment Tracking Log; U-1 Spent Fuel Pit Pump, September 18, 2011
- Protected Equipment Tracking Log; SAT 242-1 and 242-2, September 17, 2011
- Protected Equipment Tracking Log; Refuel Water Storage Tank Level, September 29, 2011
- OP-AA-108-117; Protected Equipment Program, Revision 2
- Protected Equipment Work Approval Form; 2PA47J and 2PA23J, September 22, 2011
- Protected Equipment Work Approval Form; 2PA23J, September 19, 2011
- OU-AP-104; Shutdown Safety Management Program Byron/Braidwood Annex, Revision 16
- Shutdown Safety Equipment Status Checklist, September 30, 2011 and October 1, 2011

Section 1R15: Operability Evaluations (Quarterly)

- EC 383599 02; Byron OP EVAL 11-005, Turbine Building HELB Input Errors, August 12, 2011
- IR 1240295; Two New Line Break Locations Identified During HELB Analysis, July 15, 2011
- IR 1240635; Meeting Minutes From HELB Collegial Review Board, July 16, 2011
- IR 1241028; Unit 2 Trackway Rollup Door Found Closed, July 18, 2011
- IR 1257349; OE SXCT Concrete Inspection, August 30, 2011
- IR 1260925; 0E SXCT – Followup to IR 1257349, September 08, 2011
- Regulatory Guide 1.9; Selections, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants, Rev. 3
- Letter from Cooper-Bessemer Company; Description of a Standard Engine-Generator Set for Stand-By Service in Nuclear Power Plants, May 12, 1975
- IR 0519141; Compliance with EDG 24-Hour Endurance Testing Requirements,

Corrective Action Documents As a Result of NRC Inspection

- IR 1250432; NRC Questions Regarding Byron/Braidwood Exceptions to RG 1.9, August 11, 2011
- IR 1258339; Byron Station DG 24 Hour Run Surveillance Needs to be Revised, September 1, 2011

- IR 1258343; Byron DG Full Load Reject Surveillance May Need to be Enhanced, September 1, 2011

Section 1R19: Post Maintenance Testing (Quarterly)

- WO 1216957 32; Replace 2SX011, SXCT Basin 2A/2B RTRN HDR XTIE ISOL VLV, September 15, 2011
- WO 1285766 01; 112 “B” Train 125V Battery Charger Operability Test, September 18, 2011
- WO 1324407 03; 2AF014G IST Disassembly and Inspection, October 5, 2011
- WO 1324847 03; 2AF014E IST Disassembly and Inspection, October 5, 2011
- WO 1365478 03; 2AF014H IST Disassembly and Inspection, October 5, 2011
- WO 1457225 05; OP PMT, MSO – 2SI8811B STT, September 30, 2011
- WO Task 1343413 03; STT/PIT for 2SI8811B, September 30, 2011
- MA-AA-716-100; WO Surveillance 1285766-01
- EC Request 401181; Perform ELMS-AC Run to Support Battery Charger Testing, August 29, 2011
- 1BHSR 8.4.2-2; Unit 1 Bus 112 125V Battery Charger Operability, Revision 1
- 2BOSR 0.5-2.SI.2-2.2; Unit Two 2SI8802B, 2SI8809B, 2SI8811B and 2SI8923B Stroke Time and Position Indication Test, Revision 10
- 2BOSR 7.5.7-2; Unit Two Train B Auxiliary Feedwater Flowpath Operability Surveillance Following Shutdown, Revision 6
- Issue 1270395; TYPO Found in 2BOSR 0.5-2.SI.2-2.2, September 30, 2011
- Issue 1270471; SER Point for 2SI8811B Did Not Work During Valve Stroke, September 30, 2011
- WO 01454202; EC 385198 TCCP 2VD01CB High DP Trip Time Delay, August 4, 2011

Section 1R20: Refueling and Other Outage Activities

- IR 1220803; Hose Reel Damaged by Valve Leakby, May 26, 2011
- IR 1263653; LPMS Impact Noise Alarm During 2A AF Pump Full Flow Testing, September 15, 2011
- IR 1265004; Shaw Worker Identified Loud Noise and Pipe Movement in Unit 2 TB, September 19, 2011
- IR 1265093; Polar Crane Trolley Coupling Drive Jackshaft Bolts Loose, September 19, 2011
- IR 1265412; 2B Containment Chiller Cycling, September 20, 2011
- IR 1265583; Transmitter Found Out-of-Tolerance, September 19, 2011
- IR 1265778; B2R16LL; Workers Erecting Scaffold As 2B SG Draining, September 21, 2011
- IR 1265811; NRC B2R16 Shutdown Containment Walkdown, September 19, 2011
- IR 1266061; NRC Identified D Minor Packing Leakage – 2PS9358B, September 19, 2011
- IR 1266064; NRC Identified D Minor Packing Leakage – 2PS9358C, September 19, 2011
- IR 1266067; NRC Identified D Minor Packing Leakage – 2PS9351B, September 19, 2011
- IR 1266086; Shelving Interference with Nitrogen Piping, September 21, 2011
- IR 1266531; 2RY8047 Failed Leakage, September 22, 2011
- IR 1266573; Clearance Order Taken to Working with Draining Incomplete, September 22, 2011
- IR 1268372; Pressurizer Grating was Removed Without Signage, September 26, 2011
- IR 1268433; RT Results of Field Weld #1 – Unsatisfactory, September 26, 2011
- IR 1268600; NRC Identified Issue, September 26, 2011
- IR 1267133; B2R16LL: No IMD Support Task for BUS 033W Window, September 23, 2011
- IR 1267262; Potential Safety Issue – Working on MCC’s Without a C/O, September 23, 2011
- IR 1267371; Crimp Tool Not Listed in N-EIS-000 Standard, September 23, 2011

- IR 1267606; Tube Blockage As-Found Accept Criteria Exceeded for 2A RCFC, September 24, 2011
- IR 1267617; Unguarded Open Hole Identified by 2FW012A – Safety Issue, September 24, 2011
- Outage Work Management B2R16 Shutdown Safety Independent Review, Revision 4

Section 1R22: Surveillance Testing (Quarterly)

- WO 1275696; Test of the Master CO2 Valves, May 31, 2011
- WO 1288621; 211 A Train 125V Battery Charger Operability Test, March 9, 2011
- WO 1454401; Undervoltage Simulated Start of 2A AF Pump, August 5, 2011
- WO 1434932; LLRT for P-70 – 2PS9356A and 2PS9356B
- WO 1449369; 2A Diesel Generator Operability Surveillance, July 20, 2011

Section 2RS2: Occupational ALARA Planning and Controls

- AR 1257196; NOS ID: B2R16 Draft ALARA Plan Reviews; 8/30/2011
- AR 1250259; NOS ID: RP Records Were Inaccurate or Incomplete: 8/11/2011
- AR 1250223; NOD ID: ALARA Area Requiring Management Attention; 8/11/2011
- AR 1239292; RP Program Review – Cobalt Reduction; 7/13/2011
- AR 953480; Discrepancies in Dose Excellence Plan Implementation; 8/14/2009
- AR 1185718; B1R17 RCS Cleanup Recommendations Not Implemented; 3/10/2011
- RP-AA-16; ALARA Program Description; Revision 0
- RP-AA-400; ALARA Program; Revision 8
- RP-AA-400-1001; Establishing Collective Radiation Exposure Annual Business Plan Goals; Revision 3
- RP-AA-400-1002; Dose Equalization; Revision 13
- RP-AA-400-1003; Work Group Exposure Reduction Plans; Revision 0
- RP-AA-400-1004; Emergent Dose Control and Authorization; Revision 3
- RP-AA-400-1006; Outage Exposure Estimating and Tracking; Revision 3
- RP-AA-400-1008; Exposure Goal Recovery Plans; Revision 0
- RP-AA-401; Operational ALARA Planning and Controls; Revision 13
- RP-AP-401-1402; Writers Guide for Preparation of Steam Generator Secondary Side Maintenance ALARA Plan; Revision 0
- RP-MW-403-1001; Radiation Work Permit Processing; Revision 6
- RP-AA-4003; Guidelines for Daily Radiation Protection Outage Report; Revision 4
- 2011-2015 Dose Excellence Plan; Byron Generating Station; Revision 1
- Check-In Self Assessment; NRC RP Outage Occupational ALARA Planning and Controls; 01043255; 3/18/2010
- Check-In Self Assessment; Occupational ALARA Planning and Controls; 01129114-02; 7/26/2011
- Radiation Work Permit and Associated ALARA File; RWP 100012353; B2R16 Rx Head – Disassemble and Reassemble – All Activities; Various Dates
- Radiation Work Permit and Associated ALARA File; RWP 10012372; Outage Scaffolds; Various Dates
- Radiation Work Permit and Associated ALARA File; RWP 10012384; B2R16 Steam Generator Manway/Diaphragm Removal/Installation; Various Dates
- Radiation Work Permit and Associated ALARA File; RWP 10012383; S/G Platform and Bullpen Set-Up/Tear Down and Decon Activities; Various Dates

Section 4OA1: Performance Indicator Verification (71151)

- Monthly Data Elements for NRC Reactor Coolant System (RCS) Leakage, June 2010 through June 2011

Section 4OA2: Identification and Resolution of Problems (71152)

- IR 1232153; AF X-Tie Line Mods May Lack Required NRC Permission, June 23, 2011
- IR 1260925; OE SXCT – Follow-up to IR 1257349
- IR 1264168; 1A CS Pump Did Not Start, September 16, 2011
- IR 1264294; 1CS040A Contact for Limit Switches Needs Fixed, September 16, 2011
- IR 1265290; OLR Impact Not Identified in Procedure, September 20, 2011
- IR 1265300; OLR Impact Not Identified in Procedure, September 20, 2011
- IR 1265825; Work Delay Due to Ops Not Allowing Work to Proceed, September 14, 2011
- IR 1266078; 2B DG Lube Oil/Jacket Water Temperatures Trending Down, September 21, 2011
- Unit 1&2 Standing Order; Auxiliary Feedwater Unit Crosstie Valves and 1/2BFRH.1, Log Number 11-050
- Issue 1232153; AF X-Tie Line Mods May Lack Required NRC Permission, June 23, 2011
- Issue 1265782; Challenges to AF Crosstie NRC Violation Resolution, September 09, 2011
- Final Response to Task Interface Agreement – McGuire Nuclear Station Service Water System Unit Crossties Relative to Sharing/Donating in Abnormal Procedures (TIA 2009-011), March 4, 2011
- EC 362858; The Unit 1 Portion of a Motor Driven Auxiliary Feedwater Pump Crosstie Line for Byron Units 1 & 2, Revision 0
- McGuire Nuclear Station – NRC Integrated Inspection Report 05000369/2011002 and 05000370/2011002, May 6, 2011
- IR 1082372; Unable to Perform Portions of Surveillance 0BOSR SX-SA1, June 19, 2011
- IR 1177065; Failure to Address Exceeding GL89-13 Flushing Frequency, February 18, 2011
- IR 1079917; 2RY8010A Pressurizer Safety Valve Seat Leakage, September 14, 2011
- Leakage Data for Pressurizer Safety Valves Replaced Previously; Unit 1 B1R11-B1R16 and Unit 2 B2R10-B2R16
- ½ BFR H.1; Response to Loss of Secondary Heat Sink, Revision 201

Corrective Action Documents As a Result of NRC Inspection

- IR 1257908; 1A-2A AF Pump Discharge Crosstie Regulatory Concern, August 22, 2011
- IR 1267259; Predefine to Flush SX-FP Crosstie Lines Credited Incorrectly, September 23, 2011

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
AF	Auxiliary Feedwater
ALARA	As-Low-As-Is-Reasonably-Achievable
AOT	Allowed Outage Time
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CC	Component Cooling Water
CFR	Code of Federal Regulations
DC	Direct Current
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
ET	Eddy Current Testing
FIN	Finding
ICDPD	Incremental Core Damage Probability Deficit
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
IR	Issue Report
ISI	Inservice Inspection
IST	Inservice Testing
LAR	License Amendment Request
LCO	Limiting Condition for Operation
LER	Licensee Event Report
OpEx	Operating Experience
OSP	Outage Safety Plan
psia	pound per square inch absolute
psig	pound per square inch gauge
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PRA	Probabilistic Risk Assessment
RCS	Reactor Coolant System
RFO	Refueling Outage
RMA	Risk Management Action
SDP	Significance Determination Process
SG	Steam Generator
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SX	Essential Service Water
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WO	Work Order

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Eric R. Duncan, Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50-454; 50-455
License Nos. NPF-37; NPF-66

Enclosure: Inspection Report No. 05000454/2011004 and 05000455/2011004
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ

DOCUMENT NAME: G:\DRPIII\BYRO\Byron 2011 004.docx
☐ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☐ Non-Sensitive
To receive a copy of this document, indicate in the concurrence box "C" = Copy without attach/encl "E" = Copy with attach/encl "N" = No copy

OFFICE	RIII		RIII		RIII			
NAME	Ng:dtp		SOrth		EDuncan			
DATE	11/01/11		11/01/11		11/03/11			

OFFICIAL RECORD COPY

Letter to M. Pacilio from E. Duncan dated November 3, 2011.

SUBJECT: BYRON STATION, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000454/2011004; 05000455/2011004

DISTRIBUTION:
Amy Snyder
RidsNrrDorlLpl3-2 Resource
RidsNrrPMByron Resource
RidsNrrDirsIrib Resource
Cynthia Pederson
Jennifer Uhle
Steven Orth
Jared Heck
Allan Barker
Carole Ariano
Linda Linn
DRPIII
DRSIII
Patricia Buckley
Tammy Tomczak
ROPreports Resource