July 20, 2004

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

SUBJECT: BYRON STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000454/2004004;
05000455/2004004

Dear Mr. Crane:

On June 30, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Byron Station, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on July 1, 2004, with Mr. S. Kuczynski and other members of your staff.

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

Based on the results of this inspection, one inspector-identified finding of very low safety significance (Green) is identified in the report. This finding was determined to involve a violation of NRC requirements. However, because this violation was of very low significance and because the issue was entered into your corrective action program, the NRC is treating this finding as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, 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 facility.

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

Sincerely,

/RA/

Ann Marie Stone, Chief
Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000454/2004004; 05000455/2004004
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - Byron Station
Plant Manager - Byron Station
Regulatory Assurance Manager - Byron Station
Chief Operating Officer
Senior Vice President - Nuclear Services
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-454; 50-455
License Nos:	NPF-37; NPF-66
Report Nos:	05000454/2004004; 05000455/2004004
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	4450 N. German Church Road Byron, IL 61010
Dates:	April 1, 2004, through June 30, 2004
Inspectors:	R. Skokowski, Senior Resident Inspector P. Snyder, Resident Inspector R. Alexander, Radiation Specialist D. Jones, Reactor Engineer P. Higgins, Reactor Engineer L. Kozak, Senior Reactor Engineer D. Schrum, Reactor Engineer T. Tongue, Project Engineer R. Winter, Reactor Engineer C. Thompson, Illinois Emergency Management Agency, Resident Inspector
Observers:	T. Bilik, Reactor Engineer C. Acosta, Reactor Engineer
Approved by:	Ann Marie Stone, Chief Branch 3 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000454/2004004; 05000455/2004004; on 04/01/2004-06/30/2004; Byron Station, Units 1 and 2; Identification and Resolution of Problems.

This report covers a 3-month period of baseline resident inspection and announced baseline inspections on maintenance effectiveness-periodic evaluation, inservice inspection program, and radiation protection. In addition, inspections were conducted using Temporary Instructions (TI) 2515/152 (Unit 2 only) and 2515/156. The inspections were conducted by Region III inspectors, and the resident inspectors. One Green finding, which was a violation of NRC requirements, was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG 1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. <u>Inspector-Identified and Self-Revealed Findings</u>

Cornerstone: Mitigating Systems

- Green. The inspectors identified a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion XVI, Corrective Actions, having very low safety significance for failing to identify several instances of improperly installed scaffolding, which was considered a condition adverse to quality. These improperly installed scaffolds were identified by the inspectors during plant tours on March 16, March 19, March 28, April 6, and April 7 of 2004. In each case, after being brought to their attention, the licensee took actions to correct the improperly installed scaffolding. The cross-cutting area of Human Performance was affected because the licensee personnel failed to install scaffolding in accordance with the licensee's procedure. The cross-cutting area of Problem Identification and Resolution was affected because the deficiencies were not identified during the scaffolding inspections nor were these deficiencies identified by other members of the licensee's staff. Moreover, even after the inspectors' initial identification of improperly installed scaffolding, the licensee's extent of condition review was inadequate as evidenced by the additional deficiencies later identified by the inspectors.

  The issue was more than minor because the licensee failed to perform engineering evaluations on scaffold that potentially impacted safety-related systems. The issue was similar to more than minor example 4.a of Appendix E of IMC 0612. The inspectors determined that the finding could not be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process." Therefore, this finding was reviewed by the Regional Branch Chief in accordance with IMC 0612, Section 05.04c, and determined to be of very low safety significance (Green) because in no case was the improperly installed scaffolding determine to adversely impact the operability of safety-related equipment. The issue was a Non-Cited Violation of Criterion XVI of 10 CFR 50 Appendix B. (Section 4OA2)

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 throughout the inspection period except on May 2, 2004, when power was reduced about thirteen percent for a turbine throttle valve and governor valve surveillance test as well as a swap of main feedwater pumps.

Unit 2 began the quarter shutdown for a refueling outage. On April 9, 2004, restart activities began with the unit reaching full power on April 12, 2004. Unit 2 then operated at or near full power for the remainder of the inspection quarter except for two short power reductions: on May 16, 2004, power was reduced about five percent for a main feedwater pump swap, and on June 20, 2004, power was reduced about fourteen percent for load following and a turbine throttle valve and governor valve surveillance test.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors completed two inspection samples. The first sample reviewed the licensee's response to severe thunderstorms and high winds warnings on May 12, 2004. The inspectors evaluated licensee performance by comparing actual performance to the licensee management expectations and guidelines as presented in Byron Abnormal Operating Procedures:

- 0BOA ENV-1, Adverse Weather Conditions, Revision 101;
- 1BOA ENV-1, Adverse Weather Conditions, Revision 3; and
- 2BOA ENV-1, Adverse Weather Conditions, Revision 3.

The second sample reviewed the licensee's preparations for potential high temperature conditions during the summer season. Specifically, the inspectors performed the following:

- reviewed the Updated Safety Analysis Report (UFSAR), Technical Specifications (TS) and other plant documents to identify areas potentially challenged by summer temperatures;
- reviewed applicable licensee procedures and surveillance tests appropriate for monitoring plant conditions during summer weather;
- verified through interviews and record review, that Nuclear Shift Operators were familiar with plant systems potentially affected by high temperatures and that necessary procedural and/or contingency plans were in place; and
- verified that the licensee had performed summer readiness reviews for selected plant systems including the essential service water and circulating water systems.

During the week of May 10-14, 2004, the inspectors performed a walkdown of the plant perimeter and switchyard. The purpose of the walkdown was to assess the adequacy of the protection of plant equipment and the plant's offsite power supply from possible airborne missile hazards caused by high winds. To complete this assessment, the inspectors utilized the guidance provided by the licensee's Procedure MA-AA-716-026, Station Housekeeping and Material Condition Program, Revision 1.

The inspectors also reviewed selected issues documented in Condition Reports (CR), to determine if they had been properly addressed in the licensee's corrective actions program. The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdowns

a. Inspection Scope

The inspectors performed three partial walkdowns of accessible portions of trains of risk-significant mitigating systems equipment during times when the trains were of increased importance due to the redundant trains or other related equipment being unavailable. The inspectors utilized the valve and electric breaker lineups and applicable system drawings to verify that the components were properly positioned and that support systems were lined up as needed. The inspectors also examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors used the information in the appropriate sections of the UFSAR and TS to determine the functional requirements of the systems.

The inspectors verified the alignment of the following trains:

- Unit 2 train B component cooling water train while train A component cooling water train was out of service for maintenance;
- Unit 2 train B essential service water pump during planned work on the train A pump; and
- Unit 2 train A residual heat removal system during planned work on train B.

The inspectors utilized the following references during the completion of their review:

- Control Room Drawing; Diagram of Essential Service Water M-42, Revision AG;
- BOP SX-M1; Essential Service Water System Valve Lineup, Revision 36;
- BOP SX-E2B; Essential Service Water Unit 2 Train B Electrical Lineup, Revision 1;
- BOP SX-E2; Unit 2 Essential Service Water Electrical Lineup, Revision 7; and

- BOP SX-M2B; Unit 2 Train B Essential Service Water System Valve Lineup Revision 6.

The documents reviewed during this inspection were listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

During the inspection, the inspectors finished one complete system alignment inspection of the accessible portions of the Unit 2 auxiliary feedwater system. This system was selected because it was considered both safety-related, and risk significant in the licensee's probabilistic risk assessment and the B train was classified as (a)(1) under the Maintenance Rule. The inspection consisted of the following activities:

- a review of plant procedures (including selected abnormal and emergency procedures), drawings, and the UFSAR to identify proper system alignment;
- a review of outstanding work requests on the system;
- a review of the system health information; and
- a walkdown of the system to verify proper alignment, component accessibility, availability, and current condition.

The inspectors also reviewed selected issues documented in CRs, to determine if they had been properly addressed in the licensee's corrective actions program. The documents reviewed during this inspection were listed in the Attachment to this report.

Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors conducted fire protection walkdowns that were focused on availability, accessibility, and the condition of fire fighting equipment; the control of transient combustibles and ignition sources; and on the condition and operating status of installed fire barriers. The inspectors reviewed applicable portions of the Byron Station Fire Protection Report and selected fire areas for inspection based on their overall contribution to internal fire risk, as documented in the Individual Plant Examination of External Events Report. In addition, during these inspections, the inspectors used the following reference documents:

- OP-AA-201-006; Control of Temporary Heat Sources, Revision 0;
- OP-MW-201-007; Fire Protection System Impairment Control, Revision 0; and
- OP-AA-201-009; Control of Transient Combustible Material, Revision 3.

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 that fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The Byron Station Pre-Fire Plans applicable for each area inspected were used by the inspectors to determine approximate locations of firefighting equipment. The documents listed in the Attachment to this report were also used by the inspectors to evaluate this inspection area.

The inspectors completed nine inspection samples by examining the plant areas listed below to observe conditions related to fire protection:

- 2A emergency diesel generator (EDG) day tank room (Fire Zone 9.2-3);
- 2A EDG room (Fire Zone 9.2-2);
- Auxiliary building elevation 426' (Fire Zone 11.6-0);
- Unit 2 EDG cable tunnel (Fire Zone 3.2-1);
- Division 11 engineered safety feature (ESF) switch gear room (Fire Zone 5.2-1);
- Auxiliary building elevation 364 Unit 1 containment piping penetration area (Fire Zone 11.3-1);
- Main control room (Fire Zone 2.1-0);
- Auxiliary building elevation 346 (Fire Zone 11.2-0); and
- Division 11 miscellaneous electrical equipment room (Fire Zone 5.6-1).

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

During the weeks of April 26, and May 10, 2004, the inspectors evaluated the licensee's controls for mitigating internal and external flooding by completing a semi-annual and a annual sample. The specific areas evaluated for the semi-annual internal flooding sample included the auxiliary building elevations 330', 346', 364', and 383'. During the evaluation, inspectors performed the following:

- Reviewed the licensee's design basis documents including UFSAR, Safety Evaluation Report, and applicable calculations, to identify the design basis for flood protection and to identify those areas susceptible to external or internal flooding;
- Reviewed selected abnormal operating procedures for identifying and mitigating flooding events;
- Plant configuration that may impact external flooding controls;
- Inspected areas for control of materials that could potentially clog drains, and

- Inspected the watertight doors and flood seals.

The inspectors also reviewed selected issues documented in CRs, to determine if they had been properly addressed in the licensee's corrective actions program. The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.HS)

a. Inspection Scope

The inspectors completed one biennial testing and performance review inspection sample by observing and evaluating the licensee's inspection of the following safety-related heat exchangers:

- Unit 2 train B auxiliary feedwater pump lube oil cooler;
- Unit 2 train B auxiliary feedwater pump gear oil cooler;

These heat exchangers were selected for review because essential service water was ranked high in the plant specific risk assessment and the heat exchangers were a support system directly connected to the safety-related auxiliary feedwater system.

During the inspection, the inspectors discussed the results and heat exchanger performance with the system engineer and performed an independent inspection of the heat exchangers. The inspectors observed the internals of the coolers and the associated data in the respective work packages for any abnormalities and compared the as-found conditions to the acceptance criteria. The inspectors used Licensee's Procedure ER-AA-340-1002, Service Water Heat Exchanger and Component Inspection Guide, Revision 1, as a reference document for this inspection. Additionally, the documents listed in the Attachment to this report were also used by the inspectors to evaluate this area.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

The inspectors conducted a review of the implementation of the licensee's inservice inspection program for monitoring degradation of the Unit 2 reactor coolant system boundary and the risk significant piping system boundaries.

Specifically, the inspectors conducted an onsite record review of the following eight nondestructive examination activities to evaluate compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements and to verify that indications and defects were dispositioned in accordance with the ASME Code: (This review counted as two samples.)

- Ultrasonic Examination of Weld No. 2FW87CB-6"-C01;
- Ultrasonic Examination of Weld No. 2FW87CB-6"-C02;
- Ultrasonic Examination of Weld No. 2FW87CB-6"-C03;
- Ultrasonic Examination of Weld No. 2FW87CB-6"-C05;
- Ultrasonic Examination of Weld No. 2FW87CB-6"-C06;
- Ultrasonic Examination of Weld No. 2FW87CB-6"-C07;
- Visual Examination of Unit 2 Reactor Pressure Vessel Lower Head Penetrations; and
- Liquid Penetrant Examination of Weld No. 2SI08JA-1.5", W-16.

The inspectors also reviewed the following examination from the previous outage with recordable indications that have been accepted by the licensee for continued service to verify that the licensee's acceptance for continued service was in accordance with the ASME Code: (This review counted as one sample.)

- Ultrasonic examination of a feedwater system 1FW03DD-16"-C01 weld (indications found to be I.D. geometry).

The inspectors reviewed the following pressure boundary welds for Class 1 or 2 systems which were completed since the beginning of the previous refueling outage, to verify that the welding acceptance (e.g., radiography) and pre-service examinations were performed in accordance with ASME Code requirements: (This review counted as one sample)

- Radiographic examination of a pressurizer system pipe to pipe weld 1RY32A-3", Weld 1; and
- Radiographic examination of a pressurizer system pipe to valve weld 1RY32A-3", Weld 2.

The inspectors reviewed one ASME Section XI Code replacement to verify that the replacement met ASME Code requirements. (This review counted as one sample.)

- Work Order Package 00419282-09, replacement of pressurizer system check valve (1RY8046) and pipe (1RY32A-3").

The inspectors reviewed a sample of inservice inspection related problems documented in the licensee's corrective action program to assess conformance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. In addition, the inspectors verified that the licensee correctly assessed operating experience for applicability to the Inservice Inspection group.

The inspectors also confirmed that the steam generator tube eddy current testing (ECT) scope and expansion criteria met TS requirements, Electric Power Research Institute (EPRI) Guidelines, and commitments made to the NRC; confirmed that all areas of potential degradation (based on site-specific experience and industry experience) were inspected, especially areas which are known to represent potential ECT challenges (e.g., top-of-tube sheet, tube support plates, U-bends); confirmed that the ECT probes and equipment were qualified for the expected types of tube degradation; assessed the site specific qualification of one or more techniques (e.g., equipment, data quality/noise issues, degradation mode); and assessed corrective actions for loose parts or foreign material discovered on the secondary side of the steam generator. The inspectors reviewed the following two samples of eddy current data because questions arose regarding eddy current data analyses: (This review counted as one inspection sample.)

- Steam generator 21, row 48, column 78; and
- Steam generator 21, row 44, column 82.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On April 29, 2004, the inspectors completed one inspection sample by observing and evaluating an operating crew during an "out-of-the-box" requalification examination on the simulator using Scenario "Number 04-02-OOB," Revision 0. The inspectors evaluated crew performance in the areas of:

- clarity and formality of communications;
- ability to take timely actions;
- prioritization, interpretation and verification of alarms;
- procedure use;
- control board manipulations;
- supervisor's command and control;
- management oversight; and
- group dynamics.

Crew performance in these areas was compared to licensee management expectations and guidelines as presented in the following documents:

- OP-AA-101-111, Roles and Responsibilities of On-Shift Personnel, Revision 0,
- OP-AA-103-102, Watchstanding Practices, Revision 2,
- OP-AA-103-103, Operation of Plant Equipment, Revision 0,
- OP-AA-103-104, Reactivity Management Controls, Revision 000,
- OP-AA-104-101, Communications, Revision 1, and
- TQ-AA-106-0113; Simulator Demonstration Examination Individual Competency Evaluation Form, Revision 1.

The inspectors verified that the crew completed the critical tasks listed in the above simulator guide. The inspectors also compared simulator configurations with actual control board configurations. For any weaknesses identified, the inspectors observed the licensee evaluators to verify that they also noted the issues and discussed them in the critique at the end of the session.

In addition, the inspectors utilized the following references during the completion of their review:

- Unit 1 Abnormal Operating Procedure 1BOA-RCP-1, Reactor Coolant Pump Seal Failure, Revision 102;
- Unit 1 Abnormal Operating Procedure 1BOA-SEC-1, Secondary Pump Trip, Revision 104;
- Unit 1 Emergency Operating Procedure 1BEP-0, Reactor Trip or Safety Injection, Revision 106; and
- Unit 1 Emergency Operating Procedure 1BEP-ES-0.1, Reactor Trip Response, Revision 103.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Periodic Evaluation

a. Inspection Scope

The inspectors examined the periodic evaluation report covering the period January 2002 through June 2003. To evaluate the effectiveness of (a)(1) and (a)(2) activities, the inspectors examined a number of (a)(1) action plans, functional failures, and CRs. The inspectors reviewed these same documents to verify that the threshold for identification of problems was at an appropriate level and the associated corrective actions were appropriate. Also, the maintenance rule program documents were reviewed. The inspectors focused the inspection on the following four systems (samples):

- Main Feedwater;
- Safety Injection;
- Auxiliary Power (specifically 4160 Vac); and

- Residual Heat Removal.

The inspectors verified that the periodic evaluation was completed within the time restraints defined in 10 CFR 50.65 (once per refueling cycle, not to exceed two years). The inspectors also determined that the licensee reviewed its goals, monitored Structures, Systems, and Components (SSCs) performance, reviewed industry operating experience, and made appropriate adjustments to the maintenance rule program as a result of the above activities.

The inspectors verified that the licensee balanced reliability and unavailability of SSCs including safety significant systems during the previous refueling cycle.

The inspectors verified that (a)(1) goals were established and corrective actions were appropriate to address the causes for SSCs being in (a)(1) category, including the use of industry operating experience, and that (a)(1) activities and related goals were adjusted as needed.

The inspectors verified that the licensee had established (a)(2) performance criteria, examined any SSCs that failed to meet their performance criteria, and reviewed any SSCs that have suffered repeated maintenance preventable functional failures including a verification that failed SSCs were considered for (a)(1). The inspectors also attended a Maintenance Rule Expert Panel meeting to evaluate the panels' decision-making process for changes to maintenance rule scoping, performance criteria, and (a)(2) evaluations.

In addition, the inspectors reviewed maintenance rule self-assessments that addressed the maintenance rule program implementation.

b. <u>Findings</u>

No findings of significance were identified.

.2 <u>Routine Inspections</u>

a. <u>Inspection Scope</u>

The inspectors completed two inspection samples by evaluating the licensee's implementation of the maintenance rule, 10 CFR 50.65, as it pertained to identified performance problems associated with the following systems:

- SX5 - essential service water train and unit cross-tie isolation capability; and
- Unit 2 train B emergency diesel generator

During this inspection, the inspectors evaluated the licensee's monitoring and trending of performance data for the past 2 years, verified that performance criteria were established commensurate with safety, and verified that equipment failures were appropriately evaluated in accordance with the maintenance rule. These aspects were evaluated using the maintenance rule scoping and report documents. The inspectors also verified the basis for classification as (a)(1) or (a)(2) and the criteria for change of classification. For the system reviewed, the inspectors also reviewed the significant work orders and condition reports listed in the Attachment to this report to verify that failures were properly identified, classified, and corrected, and that unavailable time had been properly calculated.

In addition, the inspectors utilized the following references during the completion of their review:

- Regulatory Guide 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2,
- NUMARC 93-01, Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2, and
- ER-AA-310; Implementation of the Maintenance Rule, Revision 2.

Additionally, the documents reviewed during this inspection were listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee’s management of plant risk during emergent maintenance activities or during activities where more than one significant system or train was unavailable. The inspectors chose activities based on their potential to increase the probability of an initiating event or impact the operation of safety-significant equipment. The inspectors verified that the evaluation, planning, control, and performance of the work were done in a manner to reduce the risk and the work duration was minimized where practical. The inspectors also verified that contingency plans were in place where appropriate.

The inspectors reviewed configuration risk assessment records, UFSAR, TS, and Individual Plant Examination. The inspectors also observed operator turnovers, observed plan-of-the-day meetings, and reviewed the documents listed in the Attachment to this report to verify that the equipment configurations had been properly listed, that protected equipment had been identified and was being controlled where appropriate, and that significant aspects of plant risk were being communicated to the necessary personnel. The inspectors verified that the licensee controlled work activities in accordance with the following:

- Nuclear Station Procedure (NSP) WC-AA-101, On-Line Work Control Process, Revision 8,
- NSP ER-AA-600, Risk Management, Revision 3,

- NSP ER-AA-310, Implementation of the Maintenance Rule, Revision 3,
- Byron Operating Department Policy 400-47, May 13, 2004, Revision 4, and.
- Byron Nuclear Power Station Probabilistic Risk Assessment, Revision 5B.

The inspectors completed five inspection samples by reviewing the following activities:

- planned concurrent work on both high head safety injection pump trains, residual heat removal train A, and emergency diesel generator train A during the Unit 2 refueling shutdown;
- planned unavailability of the Unit 1 train B containment spray pump concurrent with essential service water cooling tower fan G;
- planned unavailability of the Unit 2 train A essential service water pump concurrent with the unavailability of the Unit 1 general area containment radiation monitor;
- planned unavailability of the Unit 1 and Unit 2 train B essential service water pumps;
- planned unavailability of the Unit 2 train B residual heat removal pump concurrent with the 2C steam power operated relief valve and train C auxiliary building supply fan;

b. Findings

No findings of significance were identified.

1R14 Personnel Performance Related to Non-routine Plant Evolutions and Events (71111.14)

a. Inspection Scope

The inspectors completed one inspection sample by observing and evaluating control room operators during the following non-routine evolutions:

- startup following Byron Station Unit 2 Outage Eleven (B2R11) on April 9, 2004.

The inspectors evaluated crew performance in the areas of:

- clarity and formality of communications,
- prioritization, interpretation and verification of alarms,
- procedure use,
- control board manipulations,
- supervisor's command and control,
- management oversight, and
- group dynamics.

Crew performance in these areas was compared to licensee management expectations and guidelines as presented in the following documents:

- OP-AA-101-111, Roles and Responsibilities of On-Shift Personnel, Revision 0,
- OP-AA-103-102, Watchstanding Practices, Revision 2,

- OP-AA-103-103, Operation of Plant Equipment, Revision 0,
- OP-AA-300, Reactivity Management Controls, Revision 000, and
- OP-AA-104-101, Communications, Revision 1.

In addition, the inspectors utilized the following references during the completion of their review:

- 2BGP 100-2; Plant Startup, Revision 30;
- 2BGP 100-2T1; Plant Startup Flow Chart, Revision 13;
- 2BGP 100-3T1; Power Ascension Flow Chart, Revision 17; and
- 2BVSR XPT-3; Unit 2 Reload Tests Following Refueling, Revision 5.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors evaluated plant conditions, selected condition reports, engineering evaluations and operability determinations for risk-significant components and systems in which operability issues were questioned. These conditions were evaluated to determine whether the operability of components was justified.

The inspectors completed seven inspection samples by reviewing the following evaluations and issues:

- Operability Determination 04-001, essential service water valve coupling engagement, Revision 2
- CR 213691, 2SX136 breaker failed post maintenance testing;
- CR 214994, 2B diesel generator engine lube oil temperature off-normal alarm;
- Engineering Change 349953, Fail Open Essential Service Water Outlet Isolation Valve 1SX101A for Unit 1 A Auxiliary Feedwater Pump Oil Cooler;
- Operability Determination 04-003, control room envelope in-leakage;
- CR 219025, Part 21 issued on installed 2B diesel generator governor digital reference unit; and
- the licensee's justification for not correcting existing degrading and nonconforming conditions during B2R11.

The inspectors compared the operability and design criteria in the appropriate section of the TS including the TS Basis, the technical requirements manual (TRM) and UFSAR to the licensee's evaluations to verify that the components or systems were operable. The inspectors determined whether compensatory measures, if needed, were taken, and determined whether the evaluations were consistent with the requirements of licensee's Procedure LS-AA-105, "Operability Determination Process," Revision 1. The inspectors also discussed the details of the evaluations with the shift managers and appropriate members of the licensee's engineering staff.

The inspectors utilized the following references during the completion of their review:

- NRC Inspection Manual Part 9900: Technical Guidance; Operable/Operability: Ensuring the Functional Capability of a System or Component;
- NRC Inspection Manual Part 9900: Technical Guidance; Resolution of Degraded and Nonconforming Conditions; October 8, 1997; and
- NRC Generic Letter No 91-18: Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions, Revision 1.

The documents reviewed during this inspection were listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (Annual) (71111.17)

a. Inspection Scope

The inspectors completed one inspection sample by reviewing the following permanent plant modifications:

- Unit 2 containment floor drain sump level instrumentation modification to improve the reactor coolant system (RCS) leakage detection function.

The inspectors reviewed the sump level instrumentation modification installed during B2R11 to verify that the design basis, licensing basis, and performance capability of risk significant systems were not degraded by the installation of the modification. The inspectors considered the design adequacy of the modification by performing a review of the modification's impact on plant electrical requirements, material requirements and replacement components, response time, control signals, equipment protection, operation, failure modes, and other related process requirements.

The inspectors utilized the following references during the completion of their review:

- UFSAR;
- Technical Specifications; and
- Regulatory Guide 1.45, Reactor Coolant Pressure Boundary Leak Detection Systems, May 1973.

The documents listed in the Attachment to this report were used in the assessment of this area.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the post maintenance testing activities associated with maintenance or modification of mitigating, barrier integrity, and support systems that were identified as risk significant in the licensee's risk analysis. The inspectors reviewed these activities to verify that the post maintenance testing was performed adequately, demonstrated that the maintenance was successful, and that operability was restored. During this inspection activity, the inspectors interviewed maintenance and engineering department personnel and reviewed the completed post maintenance testing documentation. The inspectors used the appropriate sections of the TS, TRM, and UFSAR, as well as the documents listed in the Attachment to this report, to evaluate this area. The inspectors verified that the licensee controlled post maintenance testing in accordance with the following:

- Byron Administrative Procedure (BAP) 1600-11; Work Request Post Maintenance Testing Guidance; Revision 12, and
- NSP MA-AA-716-012; Post Maintenance Testing, Revision 1.

The inspectors completed five inspection samples by observing and evaluating the post maintenance testing subsequent to the following activities:

- Unit 1 and 2 train B essential service water pump suction valves following replacement on April 1, 2004;
- Unit 2 cold leg injection Valve SI8900A following emergent work on April 2, 2004;
- Unit 2 train B auxiliary feedwater pump following planned maintenance on April 8, 2004;
- Unit 2 train A essential service water pump following planned work on May 27, 2004; and
- Unit 1 train B component cooling water pump following plan maintenance on June 9, 2004.

During the review of the testing of the essential service water pump suction valves, the inspectors utilized the following reference documents:

- BOP SX-7; filling and venting the essential service water system, Revision 10-Interim;
- BOP SX-9; switching a standby essential service water pump with an operating essential service water pump, Revision 13;
- Braidwood CR 00026418; A2000-01641 unplanned entry into essential service LCOAR, April 5, 2000; and

- Braidwood Licensee Event Report (LER) 2000-001-00; 2A essential service water pump inoperable for more than the TS allowed outage time resulting from inadequate testing criteria due to a design deficiency and inadequate methodology for the return to service.

b. Findings

No findings of significance were identified.

1R20 Refueling & Outage Activities (71111.20)

a. Inspection Scope

The inspectors observed the licensee's performance during B2R11 beginning March 22, 2004, and concluding on April 9, 2004. The inspection activities described below completes the inspection sample started in the last inspection period.

The inspectors evaluated the licensee's conduct of refueling outage activities to assess the licensee's control of plant configuration and management of shutdown risk. The inspectors reviewed configuration management to verify that the licensee maintained defense-in-depth commensurate with the shutdown risk plan; reviewed major outage work activities to ensure that correct system lineups were maintained for key mitigating systems; and observed refueling activities to verify that fuel handling operations were performed in accordance with the TS, TRM, UFSAR and approved procedures. The inspectors interviewed operations, engineering, work control, radiological protection, and maintenance department personnel during their inspection activities. The inspectors also attended outage-related status and pre-job briefings as well as Radiation Protection ALARA (As Low As Reasonable Achievable) briefings. Other major-outage activities evaluated included the licensee's control of:

- containment penetrations in accordance with the TS;
- SSCs which could cause unexpected reactivity changes;
- flow paths, configurations, and alternate means for RCS inventory addition;
- SSCs which could cause a loss of inventory;
- RCS pressure, level, and temperature instrumentation;
- spent fuel pool cooling during and after core offload;
- switchyard activities and the configuration of electrical power systems in accordance with the TS and shutdown risk plan; and
- SSCs required for decay heat removal.

In addition, the inspectors evaluated portions of the restart preparation activities to verify that requirements of the TS and administrative procedure requirements were met prior to changing operational modes or plant configurations. Major restart preparation inspection activities performed included:

- verification that core reload was completed in accordance with the core loading plan for Byron Unit 2 Cycle 12;
- evaluation of foreign material exclusion control practices during significant work activities;
- verification that correct system lineups were maintained for key mitigating systems;
- verification that RCS boundary leakage requirements were met prior to entry into mode 4 (cold shutdown) and subsequent operational mode changes;
- verification that containment integrity was established prior to entry into mode 4;
- inspection of the containment building to assess material condition and search for loose debris, which if present, could be transported to the containment recirculation sumps and cause restriction of flow to the ECCS pump suctions during loss-of-coolant accident conditions; and
- verification that the material condition of the containment building ECCS recirculation sumps met the requirements of the TS and was consistent with the design basis.

The inspectors also observed portions of the plant heatup and reactor startup, to verify that the licensee controlled the plant cooldown in accordance with the TS and approved procedures.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors witnessed selected surveillance testing and/or reviewed test data to verify that the equipment tested using the surveillance procedures met the TS, the TRM, the UFSAR, and licensee procedural requirements. The inspectors also verified that the surveillance tests demonstrated that the equipment was capable of performing its intended safety functions. The activities were selected based on their importance in verifying mitigating systems capability and barrier integrity.

The inspectors completed six inspection samples by observing and evaluating the following surveillance tests:

- Unit 1 train A engineered safety features actuation system (ESFAS) instrumentation slave relay surveillance for automatic safety injection (K611);
- Unit 1 train B emergency diesel generator monthly surveillance test;
- Unit 2 emergency core cooling system (ECCS) sump inspection;
- Unit 1 train B containment spray pump ASME surveillance;

- Unit 1 ESFAS instrumentation slave relay surveillance (train B containment spray pump); and
- Unit 2 ECCS system flow balance test.

During this inspection, the inspectors used the following references:

- Sargent & Lundy Drawing 6E-1-4030 CS02 “Schematic Diagram Containment Spray Pump 1B” Revision U,
- Commonwealth Edison Drawing 6E-1-4030 CS06 “Schematic Diagram Containment Spray Eductor 1A Spray Additive Valves 1CS019A&B” Revision M,
- Commonwealth Edison Drawing 6E-1-4030 CS06 “Byron - Unit 1 Schematic Diagram Diesel Generator 1B Feed to 4.16KV ESF Switchgear Bus 142 ACB #1423” Revision W,
- Sargent & Lundy Drawing 6E-2-4030 AN061 “Schematic Diagram Monitor Light Group 6 (MLB-1) CI PH & Containment Spray” Revision E,
- Commonwealth Edison Drawing 6E-1-4030 AN008 “Schematic Diagram Annunciator Window Engraving 1UL-AN011, 012, 013, & 014 at 1PM06J” Revision R,
- Commonwealth Edison Drawing 6E-1-4030 EF58 “Schematic Diagram Reactor Protection System Master & Slave Relays Testing Circuit - Train B” Revision M,
- Sargent & Lundy Drawing 6E-2-4031 CS508 “Loop Schematic Diagram Containment Spray Eductor 1B Additive Flow Control System” Revision L,
- Exelon Nuclear Drawing 6E-1-4030EF60 “Schematic Diagram Reactor Protection System Output Relays Development Train B” Revision Y.

Additionally the inspectors used the documents listed in the Attachment to this report to verify that the testing met the frequency requirements; that the tests were conducted in accordance with the procedures including establishing the proper plant conditions and prerequisites; that the test acceptance criteria were met; and that the results of the tests were properly reviewed and recorded. In addition, the inspectors interviewed operations, maintenance and engineering department personnel regarding the tests and test results.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors completed two inspection samples by evaluating the following temporary plant modification on risk-significant equipment:

- Engineering Change 348576, swapped connection of cables to reactor head connector plate until next refueling/forced outage on Unit 2 for control rod drive mechanism fans; and

- Engineering Change 342298, electrical overspeed turbine trip probe mounting alternate method.

The inspectors reviewed these temporary plant modifications to verify that the instructions were consistent with applicable design modification documents and that the modification did not adversely impact system operability or availability. The inspectors used the following documents as references when completing the review: UFSAR, TS including the basis, and the TRM. The inspectors verified that the licensee controlled temporary modifications in accordance with Procedure NSP CC-AA-112, "Temporary Configuration Changes," Revision 7.

In addition, the inspectors utilized the following references during the completion of their review:

- NRC Administrative Letter 98-10: Dispositioning of TSs That Are Insufficient To Assure Plant Safety.

The inspectors also reviewed selected issues documented in CRs, to determine if they had been properly addressed in the licensee's corrective actions program. The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys for selected radiation areas, high radiation areas and airborne radioactivity areas, as available, in the following four radiologically significant work areas within the plant and reviewed work packages which included associated licensee controls and surveys for these areas to determine if radiological controls (including postings and barricades) were acceptable:

- Unit 2 Containment;
- Unit 2 Containment Access Facility;
- Auxiliary Building (in particular, the Penetration Area); and
- Radwaste Building.

The inspectors reviewed the radiation work permits (RWP) and work packages used to control work in these four areas and other high radiation work areas to identify the work control instructions and control barriers that had been specified. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. Workers were interviewed to assess their knowledge of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed.

The inspectors walked down and surveyed (using an NRC survey meter) these four areas to verify that the prescribed RWPs, procedures, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers (if necessary) were properly located.

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed eleven corrective action reports related to access controls written leading up to and during the most recent B2R11 refueling outage, including reports on high radiation area radiological incidents, as available. Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

1. Initial problem identification, characterization, and tracking;
2. Disposition of operability/reportability issues;
3. Evaluation of safety significance/risk and priority for resolution;
4. Identification of repetitive problems;
5. Identification of contributing causes;
6. Identification and implementation of effective corrective actions;
7. Resolution of Non-Cited Violations tracked in the corrective action system; and
8. Implementation/consideration of risk significant operational experience feedback.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.3 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed the following four activities that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- Steam Generator Eddy Current Testing and Tube Repairs [RWP No. 10003223];
- Steam Generator Secondary Side/Pre-Heater Inspections and FOSAR (Foreign Object Search and Removal) [RWP No. 10003224];
- Scaffold Staging, Building and Removal [RWP No. 10003261]; and
- Unit 2 train B chemical and volume control system (CV) Letdown Heat Exchanger Head Gasket Replacement [RWP No. 10003497].

The inspectors reviewed radiological job requirements for these four activities, including RWP and work procedure requirements, and attended ALARA pre-job briefings.

Job performance was observed with respect to these requirements to verify that radiological conditions in the work areas were adequately communicated to workers through pre-job briefings and postings. The inspectors also verified the adequacy of radiological controls (including required radiation, contamination, and airborne surveys); radiation protection job coverage (including audio/visual surveillance for remote job coverage); and contamination controls.

Radiological work in high radiation work areas having significant dose rate gradients was reviewed to evaluate the application of dosimetry to effectively monitor exposure to personnel and to verify that licensee controls were adequate. In particular, the steam generator eddy current activities involved evolutions where the dose rate gradients were severe which increased the necessity of providing multiple or repositioned dosimetry and/or enhanced job controls.

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.4 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements and evaluated whether workers were aware of the significant radiological conditions in their workplace, the RWP controls and limits in place, and that their performance accounted for the level of radiological hazards present.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.5 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation protection technician performance with respect to radiation protection work requirements and evaluated whether they were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their oversight of radiological activities was consistent with their training and qualifications with respect to the radiological hazards and work activities.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

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

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the B2R11 refueling outage work scheduled during the inspection period and associated work activity exposure estimates for the following three work activities which were likely to result in the highest personnel collective exposures:

- Steam Generator Eddy Current Testing and Tube Repairs [RWP No. 10003223];
- Steam Generator Secondary Side/Pre-Heater Inspections and FOSAR (Foreign Object Search and Removal) [RWP No. 10003224]; and
- Scaffold Staging, Building and Removal [RWP No. 10003261].

Additionally, the inspectors reviewed licensee procedures associated with maintaining occupational exposures ALARA and processes used to estimate and track work activity specific exposures.

These reviews represented two inspection samples.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities for the B2R11 refueling outage ranked by estimated exposure that were in progress, and reviewed the following five work activities of highest exposure significance or radiological challenge:

- Installation and Removal of Steam Generator Nozzle Covers [RWP No. 10003222];
- Steam Generator Eddy Current Testing and Tube Repairs;
- Steam Generator Secondary Side/Pre-Heater Inspections and FOSAR;
- Scaffold Staging, Building and Removal; and
- 2B CV Letdown Heat Exchanger Head Gasket Replacement [RWP No. 10003497].

For these five activities, the inspectors reviewed the ALARA evaluations, exposure estimates, and exposure mitigation requirements in order to verify that the licensee had established procedures, and engineering and work controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining if the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

The interfaces between radiation protection, operations, maintenance, planning, scheduling and engineering groups were evaluated by the inspectors to identify interface problems or missing program elements. The inspectors evaluated if work activity planning included consideration of the benefits of dose rate reduction activities such as shielding provided by water filled components/piping, job scheduling, and shielding and scaffolding installation/removal activities. Finally, the inspectors evaluated the integration radiological job planning activities (pre-job ALARA reviews) into work procedure and RWP documents.

These reviews represented five inspection samples.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the licensee's process for adjusting exposure estimates or re-planning work, when unexpected changes in scope, emergent work or higher than anticipated radiation levels were encountered. This review included a determination if adjustments to estimated exposures (intended dose) were based on sound radiation protection and ALARA principles, rather than adjustments to account for failures to adequately control the work. The frequency of these adjustments was reviewed to evaluate the adequacy of the original ALARA planning process. In particular, the inspectors reviewed and discussed with the RP staff the Work-In-Progress reviews conducted for the 2B CV letdown heat exchanger activities, steam generator nozzle dam installation/removal activities, and contingent/emergent work RWPs.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.4 Job Site Inspections and ALARA Control

a. Inspection Scope

The inspectors observed three of the activities identified in Section 2OS1.3 that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers. The licensee's use of ALARA controls for these work activities was evaluated using the following:

(1) The licensee's use of engineering controls to achieve dose reductions was evaluated to verify that procedures and controls were consistent with the licensee's ALARA reviews, that sufficient shielding of radiation sources was provided for and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding.

(2) Job sites were observed to determine if workers were utilizing the low dose waiting areas and were effective in maintaining their doses ALARA by moving to the low dose waiting area when subjected to temporary work delays.

These reviews represented two inspection samples.

b. Findings

No findings of significance were identified.

.5 Radiation Worker Performance

a. Inspection Scope

Radiation worker and RP technician performance was observed during work activities performed in radiological areas that presented the greatest radiological risk to workers. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and tools to be used, by utilizing ALARA low dose waiting areas, and that work activity controls were being complied with. Also, radiation worker performance was observed to determine whether individual training/skill level was sufficient with respect to the radiological hazards and the work involved.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Occupational Radiation Safety

4OA1 Performance Indicator Verification (71151)

.1 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensee's submitted materials for performance indicators (PIs) and periods listed below. The inspectors used PI definitions and guidance contained in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline" to verify the accuracy of the PI data. The following four PIs for Unit 1 and Unit 2 (8 samples) were reviewed:

- unplanned scrams per 7000 critical hours (April 2003 to March 2004);
- unplanned power changes per 7000 critical hours (April 2003 to March 2004);
- scrams with loss of normal heat removal (April 2003 to March 2004); and
- reactor coolant system specific activity (April 2003 through March 2004).

The inspectors reviewed selected applicable condition reports and data from logs, licensee event reports, and work orders from April 2003 through March 2004 for each PI area specified above. The inspectors independently reperformed calculations where applicable. The inspectors compared that information with the performance indicator definitions in the guideline to ensure that the licensee reported the data accurately.

For the reactor coolant system specific activity PI, the inspectors reviewed the licensee's Chemistry Department records and selected isotopic analyses to verify that the greatest Dose Equivalent Iodine value obtained during those months corresponded with the value reported to the NRC. The inspectors also reviewed selected DEI calculations to verify that appropriate conversion factors were used in the assessment as required by TSs. Additionally, on June 24, 2004, the inspectors observed adherence with licensee procedures for the collection and analysis of reactor coolant system samples.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action system at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Minor issues entered into the licensee's corrective action system as a result of inspectors' observations are generally denoted in the list of documents reviewed at the back of the report.

b. Findings

No findings of significance were identified.

.2 Annual Sample

Control of Scaffolding

Introduction: During this inspection period the inspectors identified several issues associated with the improper installation of scaffolding. The inspectors communicated their observations to the licensee and number of condition reports were generated. Based on the number of issues identified, the inspectors selected the review scaffolding control as an annual sample of the licensee's problem and identification and resolution program.

a. Effectiveness of Problem Identification

(1) Inspection Scope

During the course of plant tours, prior to, during and after the Unit 2 refueling outage (B2R11), the inspectors focused on verifying that installed scaffolding was completed in accordance with the licensee's procedures. This also allowed the inspectors to assess the licensee's effectiveness to identify conditions adverse to quality. In addition to inspections of installed scaffolding, the inspectors reviewed scaffolding related procedures and discussed the scaffolding installation process and requirements with the licensee's engineering, maintenance and operations staff. Also, the inspectors reviewed related condition reports to ensure that the issues were accurately documented, reviewed in a timely manner, and the extent of condition was appropriately considered.

During the course of this review the inspectors utilized the following licensee's procedures as references:

- LS-AA-125 Corrective Action Program Procedure, Revision 8;
- MA-AA-796-024, Scaffolding Installation, Inspection, and Removal, Revision 2; and
- NES-MS-04.1, Seismic Prequalified Scaffolds, Revision 4.

Additional documents reviewed as part of this inspection were listed in Attachment A of this report.

(2) Findings

Introduction: The inspectors identified a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion XVI, Corrective actions having very low safety significance (Green) for failing to identify several instances of improperly installed scaffolding, which was considered a condition adverse to quality. These improperly installed scaffolds were identified by the inspectors during plant tours.

Description: On March 16, 2004, during a walkdown of the Unit 2 penetration area to assess if pre-outage activities, such as equipment staging and scaffolding construction were not adversely impacting safety-related equipment, the inspectors noted that scaffold B4300 was in contact with a portion of the safety-related charging system piping. In addition, the inspectors noted other scaffolding in the penetration that looked very close to other safety-related equipment. The inspectors informed the shift manager of the concerns. Based on a subsequent discussion with the licensee structural engineer and a review of the licensee procedures, the inspectors ascertained that the seismic requirement for rigid scaffolds was a minimum 1/4 inch gap between the scaffold and safety-related equipment. Based on the clearance gap requirements, the scaffolding in contact with the charging system piping was not in accordance with the installation procedure and the licensee initiated CR 208999 and corrected the condition.

Later on March 16, the licensee completed walkdowns of scaffolding and identified five additional scaffolds that did not meet the seismic requirements. For three of the five scaffolds, the licensee's maintenance staff was able to correct the deficiencies, for the remaining two, engineering evaluations were completed to address the deficiencies. All five of the issues were documented in CR 208902.

During another walkdown by the inspectors on March 19, the inspectors identified seismic clearance concerns with scaffold 4656, located in the 2B auxiliary feedwater pump room. This scaffold was in the process of being constructed, and was inappropriately attached to safety-related support steel of the diesel-driven auxiliary feedwater pump. At the time, the 2B auxiliary feedwater pump was considered operable. After discussion with the inspectors, the structural engineer had the scaffolding removed and documented the issue in CR 209638. In addition, the inspectors expressed concern to the licensee management regarding the quality of their extent of condition review and corrective actions for the issues identified on March 16.

On March 28, the inspectors toured the operating unit (Unit 1) penetration area and identified three additional examples of scaffolds not meeting the specified seismic requirements. The inspectors discussed the concerns with the shift manager and showed the scaffolds in question to one of the on-watch operations department field supervisors. The concerns were acknowledged and documented in CR 211387. Later the licensee determined that one of these scaffolds had been inadvertently left in place since the Unit 1 outage in the fall of 2003. The licensee generated another CR (211824) to document the issue.

On March 30, the licensee generated a condition report (211906) documenting a potential negative trend regarding the scaffold program. As a result of this CR, the licensee initiated common cause analysis to be performed after the outage to capture all scaffolded related events and issues and to provide lessons learned prior to the next outage. The common cause analysis is scheduled to be completed in July 2004, and therefore the inspectors have not reviewed the results of the analysis.

On April 6, 2004, the inspectors found another scaffold (B4589) in the Unit 2 penetration area contacting safety-related piping, and on April 7, the inspectors questioned the seismic qualification of several permanent scaffolds within the Unit 2 containment. The licensee removed the scaffolding in the penetration area and documented the concern in CR 213703. Regarding the questions regarding the permanent scaffolding in the Unit 2 containment, the licensee's engineering staff provided supporting information to justify the adequacy of the installation. For one case, the licensee also adjusted the scaffolding to ensure adequate clearance between the scaffolding the safety-related equipment.

On April 7, 2004, based on the number of scaffolding-related issues noted by the inspectors, the licensee initiated CR 213802, which focused on the ineffectiveness of the licensee's actions to identify and prevent additional scaffolding issues.

<u>Analysis</u> The inspectors determined that failing to identify that scaffolding was not installed in accordance with the licensee's procedure was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspections Reports," Appendix B, "Issue Disposition Screening," issued on June 20, 2003. The inspectors determine that the finding was more than minor because it was similar to the more than minor examples of Section 4 of Appendix E of IMC 0612.

The inspectors determined that this deficiency affected the cross-cutting areas of Human Performance and Problem Identification and Resolution. Human Performance was affected because the licensee did not install or construct the scaffolding in accordance with the licensee's procedure. Problem Identification and Resolution was affected because the deficiencies were not identified during the scaffolding inspections nor were these deficiencies identified by other members of the licensee's staff. Moreover, even after the inspectors initial identification of some cases of improperly installed scaffolding, the licensee's extent of condition review was inadequate as evidenced by the additional deficiencies identified by the inspectors.

The inspectors determined that the finding could not be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, "Significance Determination Process." Therefore, this finding was reviewed by the Regional Branch Chief in accordance with IMC 0612, Section 05.04c, and determined to be of very low safety significance (Green) because in no case was the improperly installed scaffolding determine to adversely impact the operability of safety-related equipment. The finding was assigned to the mitigating system cornerstone for both units.

Enforcement Criterion XVI of 10 CFR 50 Appendix B states, in part, that measures shall be established to assure that conditions adverse to quality, such as nonconformances are promptly identified. Contrary to the above, in March and April 2004, on at least four occasions, the licensee failed to identify situations of scaffolding not constructed in accordance with the seismic clearance requirements specified in Procedure NES-MS-04.1, Seismic Prequalified Scaffolds, Revision 4. This violation was captured in the licensee's corrective action program as CR 213802. This violation was characterized as having very low risk significance (i.e., Green) and is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000454/2004004-01; 05000455/2004004-01).

.3 Semi-Annual Trending Review

a. Inspection Scope

The inspectors completed a semi-annual review for potential or identified trends. The purpose of this review was to determine if any potential or identified trends might indicate a more significant safety issue. The inspectors limited their focus to equipment issues that were documented in the following licensee programs or reports:

- Component Health Indicator Program;
- Rework Program;
- Engineering Department Quarterly Corrective Action Program Trend Report; and
- Maintenance Department Quarterly Corrective Action Program Trend Report.

The inspectors reviewed the above information for the past two years, and discussed these programs and reports with the applicable members of the licensee's staff. The inspectors verified that any trends identified by these programs and reports were appropriate entered and classified in the licensee's corrective action program.

In addition, the inspectors considered aspects of their day-to-day inspection activities to determine whether trends were overlooked by the licensee.

During the course of the inspection, the inspectors utilized the following licensee's procedures as references:

- LS-AA-125 Corrective Action Program Procedure, Revision 8;
- LS-AA-125-1002, Common Cause Analysis Manual, Revision 3;
- LS-AA-125-1005, Coding and Trending Manual, Revision3;

- MA-AA-716-230, Predictive Maintenance Program, Revision 2; and
- MA-AA-716-013, Rework Reduction, Revision 0.

Additional documents reviewed as part of this inspection were listed in Attachment A of this report.

b. <u>Issues</u>

No findings of significance were identified. The inspectors' review of the programs and reports found the identified trends appropriately captures and classified in the licensee's corrective action program. Also, based on a review of the data contained in these program, the inspectors did not identify any additional trends.

However, during the review of day-to-day inspections insights, specifically, during the inspection sample described in Section 4OA2.2 of this report, the inspectors identified a failure of the licensee to identify a trend regarding improperly installed scaffolding, such that the scaffolding was in contact with safety-related equipment. In addition, during a walkdown of the Unit 2 auxiliary building penetration area, the inspectors identified several valves with indications of dried boric acid corrosion. The boric acid was primarily due to inactive valve packing leaks. The inspectors specifically identified boric acid corrosion on following valves 2SI8802B, 2SI046, 2CV052D, 2CV8355D, 2CV8355A, but noted that several other valves with indications of boric acid corrosion. The concerns with specific valves identified by the inspectors were documented by the licensee in CR 213703.

As a result of the inspectors' concerns regarding the boric acid corrosion, the licensee completed a thorough walkdown of the valves in the penetration areas for both units, and identified several additional valves with indications of boric acid corrosion. Although no actual valve degradation was identified as a result of the boric acid corrosion, the licensee's Boric Acid Corrosion Control Program Owner initiated another CR (213843) noting the need to incorporate periodic walkdowns of the areas containing equipment vulnerable to boric acid corrosion, including the penetration areas and containment when accessible, and additional tracking of the indications of boric acid corrosion identified. From a regulatory perspective, because there was no actual degradation of equipment identified, the condition was not considered a condition adverse to quality and therefore, no violation of regulatory requirements occurred.

4OA3 <u>Event Follow-up</u> (71153)

.1 <u>Response to June 28, 2004 Earthquake</u>

a. <u>Inspection Scope</u>

On June 28, 2004, an earthquake was experienced in the portions of Illinois. According to the National Earthquake Center, at 1:10 A.M. local time on the morning of June 28, 2004, an earthquake with a magnitude of 4.5 occurred with the epicenter approximately eight miles northwest of Ottawa, Illinois. Although the magnitude and location of the earthquake was such that the seismic instrumentation did not indicate a problem, the operators entered the applicable abnormal operating procedures because some ground shaking was felt. The inspectors reviewed the operators' actions in accordance with the following procedures:

- 0BOA ENV-4, Earthquake, Unit 0, Revision 100;
- 1BOA ENV-4, Earthquake, Unit 1, Revision 100;
- 2BOA ENV-4, Earthquake, Unit 2, Revision 100; and
- BAR 0-38-E5, Accelerograph Accel High, Revision 7.

The inspectors also reviewed the applicable portions of the UFSAR related to seismic aspects of the Byron Station.

In addition, the inspectors verified that the licensee properly evaluated the significance of the earthquake in accordance with their emergency action levels as specified in the Exelon Nuclear Radiological Emergency Plan Annex for the Byron Station, Revision 15. The inspectors verified that there were no indications of reactor coolant system leakage, and completed visual inspections of selected safety-related system to verify no impact to system integrity or other structural damage. The systems inspected included the emergency diesel generators, spent fuel pool and associated equipment, portions of the component cooling water system, essential service water system, and auxiliary feedwater system. The inspectors also completed visual inspections of the Unit 1 and Unit 2 auxiliary building to containment building pipe penetration area, the Unit 1 trains A and D main steam safety valve room and steam tunnel, and outside structures and tanks, included the containment buildings, the essential service water cooling towers, the refueling water storage tanks, the condensate storage tanks, the primary water storage tanks and the fuel oil storage tanks.

b. <u>Findings</u>

No findings of significance were identified.

.2 <u>(Closed) LER 05000454/2003003-01; 05000455/2003003-01:</u> "Licensed Maximum Power Level Exceeded Due to Inaccuracies in Feedwater Ultrasonic Flow Measurements Caused by Signal Noise Contamination," Supplement 1. The original LER, which was reviewed in NRC IR 05000454/2003007; 05000455/2003007, described that Byron Unit 1 and Unit 2 exceeded their licensed maximum power level since the implementation of the ultrasonic flow measurement system (UFMS) in May 2000. The UFMS was installed to provide more accurate measure of feedwater flow, which in turn was used in the reactor power calorimetric calculation. Upon installation of UFMS, the licensee noted unexpected differences in the stations megawatt output when compared to the megawatts recovered when the licensee installed the UFMS at similar stations. The licensee's attempts to understand the differences were inconclusive. However, based on their evaluation the licensee verified that the UFMS was correctly installed and operating at the Byron Station. Consequently, the licensee decided to utilize the UFMS in calculated reactor power, allowing for greater megawatt output. The licensee continued to investigate the difference in megawatt output between the stations. In August 2003, the licensee installed another ultrasonic flow measuring instrument on the common feedwater header. The flow indications from this instrument were compared to the sum of the UFMS indications installed on the four feedwater branch lines. Based on this comparison the licensee determined that Byron Units 1 and 2 were operating in excesses of the licensed maximum power. As a result, the licensee reduced power on both units and utilized the original feedwater flow instruments (venturi) for determining reactor power.

The licensee submitted Supplement 1 to LER 2003003 to provide results of subsequent analysis of feedwater flow measurements. Specifically in February 2004, the licensee performed a feedwater flow measurement utilizing a radioactive tracer. The results of this test indicated that there was a non-conservative bias on the UFMS installed on the Unit 1 and Unit 2 common feedwater headers. This test also validated the accuracy of the installed venturi flow measurement system. Based on the tracer test results, the licensee determined that the worst case power level experienced since the installation of the UFMS was 102.62 percent for Unit 1 and 101.88 percent for Unit 2. Additionally, the results of the tracer test indicated that the originally determined cause of the problem that signal noise adversely impacted the ability of the UFMS to accurately calculated feedwater flow was fully developed and that the UFMS vendor was doing additional investigation to determine the cause.

The inspectors reviewed the licensee's LER and considered it closed. However, the regulatory aspects of this issue, including the determination of actual worst case power levels will be determined upon completion of the NRC's review of the associated Unresolved Item 50-454/03-02-03.

4OA4 <u>Cross-Cutting Aspects of Findings</u>

- A finding identified Section 4OA2 of this report affected the cross cutting area of human performance, in that, the licensee failed to install or construct the scaffolding in accordance with the licensee's procedure.

- A finding identified Section 4OA2 of this report affected the cross cutting area of problem identification and resolution, in that, the deficiencies were not identified during the scaffolding inspections nor were these deficiencies identified by other members of the licensee's staff. Moreover, even after the inspectors initial identification of some cases of improperly installed scaffolding, the licensee's extent of condition review was inadequate as evidenced by the additional deficiencies identified by the inspectors.

4OA5 <u>Other Activities</u>

.1 <u>Reactor Pressure Vessel (RPV) Lower Head Penetration (LHP) Nozzles (NRC Bulletin 2003-02) (Temporary Instruction (TI) 2515/152, Revision 1)</u>

a. <u>Inspection Scope</u>

The inspectors conducted a review of the licensee's activities in response to

Bulletin 2003-02, which was issued on August 21, 2003. To support the evaluation of the licensees' activities implemented in accordance with Bulletin 2003-02, TI 2515/152, "Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02)," was issued September 5, 2003, and revised November 5, 2003.

Summary

The licensee did not identify any signs of leakage from the RPV LHP nozzles or degradation of the RPV lower head.

b. Evaluation of Inspection Requirements

In accordance with requirements of TI 2515/152, Revision 1, the inspectors evaluated and answered the following questions:

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

1. Performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

   Yes. The inspectors verified that the remote visual examination of the LHP nozzles was performed by qualified and certified ASME Level II and Level III VT-2 examiners. Additionally, the licensee's inspection staff were trained on Electric Power Research Institute (EPRI) Report TR 1000975, "Boric Acid Corrosion Evaluation."

2. Performed in accordance with demonstrated procedures?

   Yes. The remote visual examination of the vessel bottom head and the penetration nozzles was performed in accordance with procedure ER-AP-335-1012, Revision 0, "Visual Examination of PWR Reactor Vessel Head Penetrations." The inspectors reviewed the videotape of the licensee's demonstration of visual resolution and noted that it was consistent with the procedure requirements.

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

   Yes. The inspectors verified that the licensee was able to identify, disposition, and resolve deficiencies.

4. Capable of identifying pressure boundary leakage as described in the bulletin and/or RPV lower head corrosion?

Yes. The inspectors verified that the remote visual examinations of the bottom mounted instrumentation nozzles were conducted in accordance with ER-AP-335-1012, Revision 0, “Visual Examination of PWR Reactor Vessel Head Penetrations.” The camera resolution was such that pressure boundary leakage as described in the bulletin and/or RPV lower head corrosion could be identified and characterized.

5. Could small boric acid deposits, as described in the Bulletin 2003-02, be identified and characterized, if present by the visual examination method used?

   Yes. Through review of in-process and videotape documentation, the inspectors verified that small boric acid deposits, as described in the Bulletin 2003-02, could be identified and characterized. However, the licensee did not identify any leakage from the J-groove welds of the LHP nozzles during the remote bare metal visual examination of the reactor vessel bottom head.

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

   The licensee performed a remote visual examination of the vessel bottom head and the lower head penetration nozzles using a video camera. The inspection was performed in accordance with procedure ER-AP-335-1012, Revision 0, “Visual Examination of PWR Reactor Vessel Head Penetrations.” Each lower head penetration nozzle was examined for 360 degrees (in 90 degree quadrants) and the entire examination was recorded on a videotape.

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

   Each lower head penetration nozzle was examined for 360 degrees (in 90 degree quadrants).

8. What was the physical condition of the RPV lower head (e.g., debris, insulation, dirt, boric acid deposits from other sources, physical layout, viewing obstructions)? Did it appear that there are any boric acid deposits at the interface between the vessel and the penetrations?

   The bottom head has vertical insulation panels that cover the sides of the vessel. Horizontal insulation panels are mounted to the vertical insulation panels. A minimum clearance of approximately eight inches existed between the bottom radius of the vessel and the horizontal insulation panels. Access to the space between the horizontal insulation panels and the bottom of the vessel is provided through twelve removable, horizontal, peripheral panels.

   A remotely powered and controlled crawler with camera and lighting was placed on top of the horizontal panel insulation allowing access for a bare metal visual examination. Each of the lower head penetration nozzles was examined for

360 degrees (in 90 degree quadrants) and the entire examination was recorded on a videotape.

The bottom head had rust colored stains attributed to be from previous cavity seal leakage. No buildup of deposits were noted on the J-groove welds and adjacent areas. There was no indication of leakage from the J-groove welds, which would have easily penetrated the stained surface.

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

   None. The bare metal remote visual inspections did not identify any materiel deficiencies associated with the LHP nozzles.

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

    None. There were no impediments to the remote visual examinations. Access to the LHP nozzles was provided through one of the twelve bottom head peripheral removable insulation panels. A minimum clearance of approximately eight inches existed between the bottom radius of the vessel and the horizontal insulation panels. Each of the lower head penetration nozzles was examined for 360 degrees (in 90 degree quadrants) and the entire examination was recorded on a videotape.

11. Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components above the RPV lower head?

    There were rust colored stained areas attributed to be from previous cavity seal leakage. No buildup of deposits were noted.

12. Did the licensee take any chemical samples of the deposits? What type of chemical analysis was performed (e.g., Fourier Transform Infrared (FTIR), what constituents were looked for (e.g., boron, lithium, specific isotopes), and what were the licensee's criteria for determining any boric acid deposits were not from RCS leakage (e.g., Li-7, ratio of specific isotopes, etc.)?

    No. There were no deposits from which to take samples, only rust colored stains.

13. Is the licensee planning to do any cleaning of the head?

    No. There were no deposits; only stains.

14. What are the licensee's conclusions regarding the origin of any deposits present and what is the licensee's rationale for the conclusions?

No deposits were identified.

c. Findings

No findings of significance were identified.

.2 TI 2515/156, Offsite Power System Operational Readiness

a. Scope

The inspectors performed an operational readiness review of the offsite power (OPS) systems in response to TI 2515/156, “Offsite Power System Operational Readiness.” Specifically, the inspectors gathered and reviewed licensee data supporting the following requirements:

- Appendix A to 10 CFR Part 50, General Design Criterion (GDC) 17, “Electrical Power Systems,” to minimize the likelihood of losing offsite power on loss of the generating unit;
- Appendix B to 10 CFR Part 50, Criterion III, “Design Control,” to confirm the design interface between the nuclear power plant (NPP) and the regional transmission operator (RTO);
- Criterion XVI, “Corrective Actions,” to confirm the licensee’s assessment of the industry operating experience from the August 14, 2003 grid event;
- licensee TSs for determining operability of the OPS; and
- the licensee’s assumptions used in the station blackout analysis performed per 10 CFR 50.63, “Loss of All Alternating Current Power,” to determine an acceptable coping time.

The inspectors also reviewed the licensee’s requirements for assessing risk when performing work on the OPS or the emergency onsite power systems per 10 CFR 50.65(a)(4).

b. Observations and Findings

No findings of significance were identified. Based on the inspection, no immediate operability issues were identified. In accordance with TI 2515/156 reporting requirements, the inspectors provided the required data to the headquarters staff for further analysis. Therefore, this TI is closed for both units.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. S. Kuczynski and other members of licensee management at the conclusion of the inspection on July 1, 2004. The inspectors did review and dispose of two proprietary documents. The inspectors asked the licensee whether any other materials examined during the inspection should be considered proprietary. No other proprietary information was identified.

.2 Interim Exit Meeting

An interim exit meeting was conducted for:

- Maintenance Effectiveness Periodic Evaluation with Mr. S. Kuczynski on April 30, 2004.

- Inservice Inspection and Temporary Instruction TI 2515/152 with Mr. S. Kuczynski on March 31, 2004.

- Occupational Radiation Safety ALARA and access control programs inspection with Mr. D. Hoots on April 7, 2004.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Kuczynski, Site Vice President
D. Hoots, Plant Manager
B. Adams, Engineering Director
D. Combs, Site Security Manager
B. Dean, Maintenance Rule Coordinator
D. Goldsmith, Radiation Protection Director
W. Grundmann, Regulatory Assurance Manager
K. Hansing, Nuclear Oversight
Y. In, PRA Engineer
S. Kerr, Chemistry Manager
S. Koernschild, Inservice Inspection
R. Kolo, Training Manager
R. McBride, Inservice Inspection
D. Palmer, Radiation Protection - ALARA
J. Smith, Byron Engineering
M. Snow, Work Management Director
S. Stimac, Operations Manager
B. Youman, Maintenance Manager

Nuclear Regulatory Commission

A. Stone, Chief, Projects Branch 3, Division of Reactor Projects
G. Dick, Project Manager, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000454/2004004-01 05000455/2004004-01	NCV	Failure to Identify Several Situations of Scaffolds Not Meeting the Seismic Clearance Specifications (Section 4OA2.2)

Closed

05000454/2003003-01 05000455/2003003-01	LER	Licensed Maximum Power Level Exceeded Due to Inaccuracies in Feedwater Ultrasonic Flow Measurements Caused by Signal Noise Contamination (Section 4OA3.2)

Discussed

50-454/03-02-03	URI	Evaluation for Unit 1 Potentially Exceeding Licensed Thermal Power Limits (Sections 4OA3.2)

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather Protection

Exelon Letter; Byron Station Summer Readiness, June 11, 2003, Revision 1
Decision Evaluation; Unit 1 GC System, April 28, 2004
Summer of 2004 - Action Item List, Updated May 03, 2004
WO 577011; High Temperature Protection (Outside Air Temperature >70 Degrees), May 07, 2004
0BOSR XHT-A1; High Temperature Equipment Protection, Revision 6
CR 182770; Issues from Summer Readiness Critique, October 23, 2003
CR 185010; RSH Auger Oil Reservoir Found with No Oil, November 06, 2003
CR 208020; NOS Identified Weaknesses in Summer Readiness Critique Case, March 12, 2004
CR 220503; Walkdown 345KV Switchyard FME Issues, May 12, 2004 (NRC Identified)
CR 223038; Unplanned LCOAR Entry Due to National Weather Service Tornado Watch, May 23, 2004
CR 223047; UHS Limiting Condition for Operation (LCO) 7.9 Not Entered for Tornado Warning, May 21, 2004
OP-AA-108-109; Seasonal Readiness, Revision 1
1BOA ENV-1; Adverse Weather Conditions, Revision 3
MA-AA-716-026; Station Housekeeping/Material Condition Program, Revision 1

1R04 Equipment Alignment

BOP AF-E2; Auxiliary Feedwater Unit 2 Electrical Lineup, Revision 4
BOP-AF-M2; Auxiliary Feedwater System Valve Lineup, Revision 9
BOP CC-M2A; Train “A” Component Cooling System Valve Lineup, Revision 3
BOP RH-E2A; Unit 2 Residual Heat Removal System, Electrical Lineup, Revision 3
BOP RH-M2A; Train “A” Residual Heat Removal System Valve Lineup, Revision 6
BOP SX-M2A; Train “A” Essential Service Water System Valve Lineup, Revision 3
Clearance Order Checklist 0027294
Drawing M-122; Diagram of Auxiliary Feedwater
Drawing M-66; Sheet # 3A and Sheet #3B, Diagram of Component Cooling
Drawing M-66A; Sheet #1, Composite Diagram of Component Cooling
Drawing M-42; Sheet # 1A, 1B and 2B, Diagram of Essential Service Water
Drawing M-137; Diagram of Residual Heat Removal, Revision BB
Quarterly SHIP System Reports, December 1, 2003, and March 1, 2004

System Engineer Notebook, Diary of Significant Events
Unit 2 Auxiliary Feedwater Completed Work Orders, June 22, 2004
CR 133982; Long Standing Equipment Deficiencies, December 4, 2004

CR 185010; RSH Auger Oil Reservoir Found with No Oil, November 06, 2003
CR 195963; AF System Abnormalities Discovered During Troubleshooting, January 17, 2004
CR 204052; Oil Sample Indicates Water Contamination on 2AF01PB Pump, February 3, 2004
CR 210825; 1B AF Pump Speed Increaser Gear Box Oil Level, February 5, 2004
CR 211313; AF Suction Pressure Transmitter Calibration, March 25, 2004
CR 213628; 2B AF Pump Tripped on High Jacket Water Temperature During Surveillance, April 7, 2004
CR 218184; 2A AF Pp LO Reservoir and 2B AF Pp Gearcase LO Levels Elevated, May 1, 2004
CR 218741; NRC Identified Concerns, May 04, 2004 (NRC Identified)
CR 219302; AF Flow Control Setting Low Alarm, May 6, 2004
Maintenance Rule Expert Panel Meeting Notes, March 18, 2004
Plant Health Committee; Auxiliary Feedwater Work Windows, June 14, 2004
ER-AA-310-1005; Maintenance Rule (a)(1) Disposition Checklist and Documentation Summary for AF1, Provide Emergency Water Supply to Steam Generators, Revision 1

1R05 Fire Protection

OP-AA-201-006; Control of Temporary Heat Sources, Revision 0
OP-MW-201-007; Fire Protection System Impairment Control, Revision 0
Drawing M-518; Auxiliary Building-Process Pipe Sleeve Installing Schedule
Drawing TM-1; High Density Silicone Elastomer Radiation Seal for Stationary Mechanical Penetrating Members
Drawing S-716; Auxiliary Building Foundation Section 1-1, Byron Station Units 1 & 2
Drawing M-579; Low Pressure Co2 Fire Extinguishing System, Byron/Braidwood Stations, Unit 1 & 2, Revision C
CR 216592; Fire Inside 10 Ton CO2 Tank Enclosure, April 23, 2004
CR 222036; Deficiencies Identified During NRC Walkdown of Area 5, May 17, 2004 (NRC Identified)
CR 228707; Auxiliary Building Storage Potential Seismic Concern, June 15, 2004

1R06 Flood Protection Measures

Calculation 3C8-1281-00; Auxiliary Building Flood Protection, Revision 8,
CR 100417; IN 2002-12, Submerged Safety-Related Electrical Cables, March 21, 2004
CR 217773; NRC Walkdown, Flooding Concern on 346' Auxiliary Building, April 29, 2004, (NRC Identified)
WO 506435 01 EM Cable Vault Submerged Safety Related Cable Inspection, August 18, 2003
Calculation WR-BY-PF-10; Effect of Local Probable Maximum Precipitation (PMP) at Plant Site, Revision 4

1R07 Heat Sink Performance

HX/Component Inspection Data Sheet, 2B AF Pp Gear Oil Cooler, and Lube Oil Cooler March 30, 2004

2B Diesel-Driven AF Pump Lube Oil Cooler and Lube Oil Cooler Inspection Report, April 01, 2004
WO 527858; 2AF01AB - HX Inspection Per Generic Letter 89-13, March 31, 2004

1R08 Inservice Inspection

PDI-UT-1; Ultrasonic Examination of Ferritic Pipe Welds; dated August 27, 2003
EXE-ISI-11; Liquid Penetrant Examination; dated August 30, 2002
CR No. 202839; VT-2 Work Order Descriptions Are Inadequate

1R12 Maintenance Effectiveness

Maintenance Rule Periodic Assessment #5; January 2002-June 2003
Maintenance Rule (a)(1) Disposition Checklist and Documentation Summary for FW1; Revision 0 and 1
Maintenance Rule (a)(1) Disposition Checklist and Documentation Summary for SI1; Revision 0
Expert Panel Meeting Minutes; dated April 12, 2002
Expert Panel Meeting Minutes; dated August 1, 2002
Expert Panel Meeting Minutes; dated August 12, 2002
Expert Panel Meeting Minutes; dated June 19, 2003
Expert Panel Meeting Minutes; dated October 31, 2003
ER-AA-310-1005; Maintenance Rule - Dispositioning Between (a)(1) and (a)(2); Revision 1
ER-AA-310-1006; Maintenance Rule - Expert Panel Roles and Responsibilities; Revision 1
Maintenance Rule Check-In Self-Assessment Report; dated March 22, 2004
BB PRA-017.04; Maintenance Rule Performance Criteria; Revision 1
BB PRA-017.03B; Maintenance Rule Performance Criteria; Revision 2
CR 076849; Weld Leak in 1SI081; dated September 27, 2001
CR 098784; B1R11 Shutdown Events and Unexpected Occurrences; dated March 12, 2002
CR 100716; Loss of Start Capability on 2A Feedwater Pump; dated March 24, 2002
CR 107725; Trouble Opening 2A Feedwater Pump Suction Valve; dated May 11, 2002
CR 115925; RWST Heater is Leaking; dated June 8, 2002
CR 155971; 2A Feedwater Pump Shutdown Due to High Motor Bearing Temperatures; dated April 27, 2003
CR 180469; U2 RWST Heater Has a Leak; dated October 10, 2003
CR 188595; 2A AF Pump Shaft Driven Oil Pump Seal Leak; dated December 1, 2003
CR 195433; 2B Auxiliary Feedwater Pump Outboard Bearing Oil Leak Resulting in Inoperability of the Pump; dated January 15, 2004
CR 213373; 2B DG LO Temperature is Abnormal During Testing, April 6, 2004
CR 214994; 2B DG Engine Lube Oil Temperature Off-Normal Alarm, April 14, 2004

CR 217897; NRC Maintenance Rule (MAINTENANCE RULE (MR) Observation: Timeliness in (a)(1) Process; dated April 30, 2004
CR 217898; NRC MAINTENANCE RULE (MR) Observation: (a)(1) Action Plan Goal Setting; dated April 30, 2004

CR 217899; NRC MAINTENANCE RULE (MR) Observation: (2)(2) Performance Criteria; dated April 30, 2004
Risk Configurations Week of June 7, 2004, Revision 1
System Engineer Notebook
Shift Managers Log
System Trending Data (Electronic Version)
Expert Panel Scoping Determination
Technical Specifications - Applicable Portions
(a)(1) Determination Documentation, January 10, 2003
2B DG System/Component Walkdown Checklist, February 6, 2004, October 16, 2003, July 3, 2003, March 14, 2003
System Health Overview Reports, June 2003
Quarterly System Health Reports, March 1, 2004, December 1, 2003
MA-AA-716-004; Troubleshooting Data Sheet

1R13 Maintenance Risk Assessments and Emergent Work Control

Licensee Weekly Risk Summary Sheets for Week of March 29, 2004
Licensee Weekly Risk Summary Sheets for Week of May 10, 2004
Licensee Weekly Risk Summary Sheets for Week of May 24, 2004
Licensee Weekly Risk Summary Sheets for Week of June 7, 2004

1R15 Operability Evaluations

Issue#: IR 00226880; Potential Missed LER on SX Valve Inoperabilities, June 8, 2004, (NRC Identified)
CR 202230; Actuator to Valve Coupling Engagement Extent of Condition, February 17, 2004
CR 219025; Part 21 Issued on Installed 2B DG Digital Reference Unit, May 3, 2004
CR 219310; Control Room Envelope In-Leakage, April 30, 2004
CR 232158; High Bearing IL Temperatures During ASME Run, June 28, 2004
10 CFR 21-0088; Reporting of Defects and Non-Compliance, April 30, 2004
LS-AA-105; Operability Determinations, Revision 1
TCCP/EC #349953, Revision 0

1R17 Permanent Plant Modifications

CR 208788; Cat ID 401161 Expire Shelf Life. Need for GEMs Mod., March 16, 2004
CR 209345; GEMs Level Sensor Mounting (EC 337255), March 18, 2004
CR 211280; B2R11 Lessons Learned - GEMs Mod Related; Oil Separator Siphon, March 27, 2004
CR 212217; Unexpected Interference Causes Work Delay on GEMs Mod, March 31, 2004

50.59 Evaluation No. 6G-04-0002; EC 337255 Revision 1, Unit 2 Containment Floor Drain Sump Level Instrumentation Modification to Improve the RCS Leakage Detection Function, Revision 1
EC# 337255; Design Considerations Summary, Revision 1

1R19 Post Maintenance Testing

WO 669486 01; 2A SX Pump ASME Surveillance, May 27, 2004
WO 99237296 01; Change Pump Coupling Grease, May 27, 2004
WO 99237296 02; Post-Maintenance Test (PMT) - Vibration Check Per ASME BVSR, May 27, 2004
WO 672269; 2BOSR 7.5.4-2, 2B AF PP Run, April 08, 2004
2BOSR 7.5.4-2; Unit 2 Diesel Driven Auxiliary Feedwater Pump Monthly Surveillance, Revision 5
CR 212548; VT-2 Requirements for 1SX002B, April 01, 2004
CR 212550; Incorrectly Specified POST-MAINTENANCE TEST (PMT) for 1SX002B, March 31, 2004
CR 212923; BMP 3203 Had Incorrect Test Pressure for Pressure Cap, April 03, 2004
CR 215287; Lesson Learned from 2SX001B LAO Challenge Meeting, April 16, 2004
CR 217856; Flood Seal Installed on 2SX001B - EMD Work Outstanding, April 29, 2004
Project Lesson Learned; Project Title, 1/2SX001B Valve Replacement
WO 493159 11; EP MOV Valve Testing-1SX001B-After Valve Replacement, April 01, 2004
WO 493159 12; OP POST-MAINTENANCE TEST (PMT) - Stroke and Pump Start, April 01, 2004
WO 493159 13; SEP POST-MAINTENANCE TEST (PMT) - VT2 (4 Hour Hold Time), April 01, 2004
WO 493159 39; OPS POST-MAINTENANCE TEST (PMT) - !SX01FB Inspection Cover Non-ISI Visual, April 01, 2004
WO 494655; Auxiliary Feedwater Diesel Prime Mover Inspection, April 07, 2004
2BVSR z.7.a.1; Auxiliary Feedwater Diesel Prime Mover Inspection, Revision 8
WO 527861; Unit 2 Motor Driven AF Pump - Clean and Inspect Lube Oil, April 05, 2004
WO 533904 01; MM Change Pump Coupling Grease,
WO 542911; Inspect AF Diesel Starting Motors and Bendix Gear, April 07, 2004
WO 541178; Replace AF Diesel Fuel Injectors, April 07, 2004
WO 580634; Pump Shaft Lubricant, June 8, 2004
WO 680630; Check Calibration of 2PT-AF055, April 08, 2004
WO 508503; Diesel Driven AF PP Inspection to Support 2BVSR Z.7.A.1, April 07, 2004
WO 404385; AF Diesel Flywheel Inspection (Non-Intrusive), April 07, 2004
WO 577761 01; Safety Injection System Valve Stroke Test - BVSR 5.5.8.SI.2-1 ECCS Full Flow SI to CL, March 16, 2004
WO 674619; 1B CC PP ASME Pump Surveillance, June 9, 2004
WO 99201919; Replace Solenoid, April 08, 2004
WO 99272915; Uncouple/Recouple and Realign Motor to Pump, June 8, 2004
WO 99272915 01; EM Perform 10 year PM and Overhaul of Motor
WO 99272915 05; Post Maintenance Uncoupled Run 1CC01PB-M, June 9, 2004
BHP 4200-52; Polarization Index and Impedance Tests, Revision 13

BMP 3229-1; Preventive Maintenance of Miscellaneous Pump Couplings, Revision 8
Unit 2 ECCS System Flow Balance Test , April 2, 2004
1BVSR 5.5.8.CC.1-2; Unit 1 ASME Surveillance Requirements for Component Cooling Pump 1CC01PB, Revision 8
2BVSR 5.C.3; Unit 2 ECCS System Flow Balance Test, Revision 3

EC341402; Flo-Seris Evaluation of Replacement Impeller for the 2A CV Pump, Revision 0
WO 485441 02; Task Profile, May 27, 2004

1R20 Refueling and Outage Activities

B2R11 SSRB Meeting, March 9, 2004
B2R11 Shutdown Safety Profile as of March 15, 2004
PORC 04-010; B2R11 Shutdown Risk Plan, March 18, 2004
CR 211931; Underload on Fuel Bundle S51E, March 28, 2004
CR 213304; NRC Comments From Tour of Unit 2 Containment on April 5, 2004 (NRC Identified)
CR 213703; NRC Senior Resident Walkdown Issues, April 05, 2004 (NRC Identified)
CR 213801; Containment Walkdown Items, April 7, 2004 (NRC Identified)
PORC # 04-014; Byron Pre-PORC Management Challenge Meeting Agenda for B2R11 Mode 4 Startup

1R22 Surveillance Testing

1BOSR 3.2.8-644B; Unit 1 ESFAS Instrument Slave Relay Surveillance (Train B Automatic Containment Spray - K644), Revision 1
WO 501426 01; Visual Inspection of the Containment Recirculation Sumps - A ECCS Sump Inspection, April 5, 2004
WO 501426 02; Visual Inspection of the Containment Recirculation Sumps - B ECCS Sump Inspection, April 5, 2004
WO 665766; 1BOSR 3.2.8-644B, Train B CS-K644/CS, May 12, 2004
WO 686556; 1A Diesel Generator Operability Monthly Surveillance, May 14, 2004
1BVSR 6.6.4-2; Unit 1 ASME Surveillance Requirements for the 1B Containment Spray Pump, Revision 4
CR 212887; ECCS Full Flow Procedure Adherence/Adequacy Deficiencies, April 03, 2004
CR 212911; Unit 2 CV to Cold Leg ECCS Procedure and Test Results, April 03, 2004
CR 213032; Additional Error Discovered in Surveillance 2BVSR 5.c.3, April 04, 2004
CR 220841; Update Needed for Labeling of 1/2FI-SI006 - Attempt #3, May 12, 2004 (NRC Identified)
WR 144616; Change Noun Name Tag on Flow Instrument to Read CS PP 1A/B Recirculation Flow Indicator, May 13, 2004
WO 628137; SI Pump ECCS Flow Balance Test, April 2, 2004
WO 640349; Perform 1BVSR 6.6.4-2: 1B CS ASME Pump Run, February 12, 2004
1BVSR 6.6.4-2.BY01; 1VC01PB ASME Acceptance Criteria Data Sheet, Revision 0
2BVSR 5.C.3; Unit 2 ECCS System Flow Balance Test, Revision 4
EC 341402; Flo-Series Evaluation of Replacement Impeller for the 2A CV Pump, Revision 0

EC 339829; Flo-Series Evaluation of Replacement Impeller for the 2B CV Pump, Revision 0
EC 339887; Operability Evaluation of 2B CV Pump Impeller Change Out
WO 667740; Slave Relay Train A SI-K611/DG, VA (WK I), May 14, 2004

1BOSR 3.2.8-611A; Unit 1 ESFAS Instrumentation Slave Relay Surveillance (Train A Automatic Safety Injection - K611), Revision 0
1BOSR 8.1.2-1; Unit One 1A Diesel Generator Operability Surveillance, Revision 10
LS-AA-104-1001; 50.59 Review Coversheet Form - Unit 2 ECCS System Flow Balance Test, Revision 1
AD-AA-101-1002; Procedure Approval Form, Revision 3
2BVSR 5.2.8-1; Unit 2 Visual Inspection of the ECCS Recirculation Sumps, Revision 3

1R23 Temporary Plant Modifications

MA-BY-726-670; Reactor Head Determination, Electrical Testing and Determination, Revision 2
CR 130600; Operating Log Keeping Deficiency, November 7, 2004
CR 155026; LCOAR Entry for Slave Relay Surveillance, April 21, 2003
CR 199577; QRT Grade 3 - Temporary Configuration Change (TCC) Installation Instruction Incomplete, February 4, 2004
CR 199745; Braidwood CR on TCC for Turbine Overspeed Trip System, February 5, 2004
CR 214107; CDM Fans Wired Incorrectly, 2B/C Breakers Control 2A/D Fans, April 09, 2004
CR 217633; Equipment Status Tags (EST) on the Remote Shutdown Panel, April 27, 2004 (NRC Identified)
Schematic Diagram Turbine Generator Trip Part 2, 6E-1-4030TG04, Revision R
1BOSR 3.2.8-640A; Unit 1 ESFAS Instrumentation Slave Relay Surveillance (Train A Turbine Trip - K640), Revision 0
CC-MW-112-1001; Attachment 11, TCCP Monthly Review Sheet, April 3, 2004
WO 565334; OP Post Maintenance Test, June 10, 2003
Work Package 00565344-01; Install TCC for Turbine Overspeed Alternate Mounting EC 342298, Revision 0
EC 346332; Disable Electrical Overspeed Turbine Trip Due to Module Failure, December 16, 2003
1BOL EH1; LCOAR Turbine Trip Actuation Equipment, Revision 0
2BOL EH1; LCOAR Turbine Trip Actuation Equipment, Revision 0

2OS1 Access Control to Radiologically Significant Areas

CR 204029; Rad Postings Found Degraded and Outside on the Ground; dated February 25, 2004
CR 204079; Rad Posting Direction Not Recognized Prior to Task Start; dated February 25, 2004
CR 206622; Ladder in Place to Access U2 CAF Roof, No Documented Survey; dated March 6, 2004
CR 209387; Misunderstanding of Radiation Protection Briefing; dated March 18, 2004

CR 209710; Labels for Unit 2 Containment Penetration Area; dated March 20, 2004
CR 210422; Wrong RWP Used During Filter Change; dated March 23, 2004
CR 210895; Exceeded Digy [Electronic Dosimetry] Dose Rate Alarm; dated March 25, 2004

CR 211018; Oil Separator Repair Charged to GEMs RWP - Not Estimated; dated March 26, 2004
CR 211055; Individual Exceeded RWP Accumulated Dose Limit; dated March 26, 2004
CR 211261; NOS Identified Log Keeping Issues at S/G Control Point; dated March 27, 2004
CR 212233; Check Valve 2CV8323A Deferred Out of B2R11; dated March 31, 2004
Prompt Investigation Report for CR 211055; dated March 27, 2004
RWP No. 10003222; B2R11: Install and Remove S/G Nozzle Covers; Revision 5
RWP No. 10003223; B2R11: S/G Eddy Current Testing and All Tube Repairs; Revision 1
RWP No. 10003224; B2R11: Secondary Side/Pre-Heater Inspections and foreign object search and retrieval (FOSAR); Revision 0
RWP No. 10003261; B2R11: Scaffold Staging, Building, and Removal (Aux & CNMT); Revision 1
RWP No. 10003497; 2B CV Letdown Heat Exchanger - Replace Head Gasket Replacement; Revision 0

2OS2 As Low As Is Reasonably Achievable (ALARA) Planning and Controls

ALARA Plan for RWP No. 10003222; Revision 5
ALARA Plan for RWP No. 10003223; Revision 1
ALARA Plan for RWP No. 10003224; Revision 0
ALARA Plan for RWP No. 10003261; Revision 1
B2R11 ALARA Index (Spreadsheet of Outage RWP Dose Estimates); dated March 11, 2004
B2R11 Exposure Tracking (Spreadsheet of Outage RWP Actual Doses); dated April 5, 2004
Check-In AT No. 188564-04; B2R11 Outage Readiness and Preparation; dated March 11, 2004
CR 204394; Dose Initiative to Install a Shielding Ring Around the S/G's; dated February 26, 2004
CR 210705; Scaffolding and Rad Dose Planning for 2B S/G Upper Bundle Inspection; dated March 25, 2004
CR 211243; RWP Approved Dose Limit Exceeded; dated March 27, 2004
CR 211376; Dose Rates Inside the U-2 S/G Channel Heads; dated March 28, 2004
CR 213362; Exposure Goal for B2R11 Exceeded; dated April 5, 2004
RP-AA-400; ALARA Program; Revision 2
RP-AA-401; Operational ALARA Planning and Controls; Revision 2
Work-In-Progress Reviews for RWP No. 10003497; dated March 27 and 29, 2004
Work-In-Progress Review for RWP No. 10003222; dated March 29, 2004

4OA1 Performance Indicator Verification

Unit 1 and Unit 2 Reactor Coolant Loop - Summaries of Nuclide Activity, March 1, 2004, March 7, 2004, December 29, 2003, December 15, 2003, and June 24, 2004
Technical Specifications - Applicable Portions
WR 119642; 1FW540 is Starting to Show Signs of Erratic Behavior

Operations Narrative Logs; January 4, 2004 through January 5, 2004
Operations Narrative Logs; May 18/2003 through May 19, 2003
WO 578609; Turbine Throttle and Governor Valve Quarterly Surveillance
Operations Narrative Logs; July 06, 2003 through July 07, 2003
Operations Narrative Logs; January 10, 2004 through January 13, 2004
WO 581120; Turbine Throttle and Governor Valve Quarterly Surveillance
WO 615481; Turbine Throttle and Governor Valve Quarterly Surveillance
Operations Narrative Logs; September 14, 2003 through September 15, 2003
Operations Narrative Logs; February 04, 2004 through February 06, 2004
Operations Narrative Logs; March 22, 2004 through March 23, 2004
Operations Narrative Logs; September 22, 2003 through September 23, 2003
Operations Narrative Logs; October 13, 2003 through October 14, 2003
WO 537021; 1BOSR 3.G.4-1, Unit 1 Throttle Valve Governor Valve (TVGV) Surveillance
Operations Narrative Logs; May 27, 2003 through May 28, 2003
Byron Unit 2 PI: IE03; Unplanned Power changes per 7,000 Critical Hours
Byron Unit 2 PI: IE02; Scrams with Loss of Normal Heat Removal
Byron Unit 2 PI: IE01; Unplanned Scrams per 7,000 Critical Hours
Byron Unit 1 PI: IE01; Unplanned Scrams per 7,000 Critical Hours
Byron Unit 1 PI: IE03; Unplanned Power Changes per 7,000 Critical Hours
Byron Unit 1 PI: IE02, Scrams with Loss of Normal Heat Removal
WO 562527; Turbine Throttle and Governor Valve Quarterly Surveillance
Monthly Data Elements for NRC Unplanned Power Changes per 7,000 Critical Hours, November 2003 through March 2004
Monthly Performance Indicator (PI) Data Elements for Unplanned Power Changes per 7,000 Critical Hours, April 2003 through October 2003
Monthly data Elements for NRC/WANO Unit/Reactor Shutdown Occurrences, November 2003 through March 2004
Monthly PI Data Elements for Unplanned Scrams with Loss of Normal Heat Removal, April 2003 through October 2003
Monthly PI Data Elements for Unplanned Scrams per 7,000 Critical Hours, April 2003 through October 2003
NEI 99-02; Regulatory Assessment Performance Indicator Guideline, Revision 2
LS-AA-2090; Monthly Performance Indicator Data Elements for Reactor Coolant System Specific Activity; Revisions 3 and 4 (data for April 2003 - March 2004)
BCP 300-37; Degassing Reactor Coolant; Revision 6
BCP 300-29; Chemical and Volume Control System (CVCS) Letdown HX (CVCS Demin Inlet) HRSS Grab Sample, Revision 12
BCP 210-22; Isotopic Analysis on the Canberra Counting Room System, Revision 5

4OA2 Identification and Resolution of Problems

CR 206959; 26A HTR Emergency Drain Valve Open - CB Flow Hi - FW NPSH Low, March 8, 2004
CR 208902; Seismic Scaffold Issues, March 16, 2004
CR 208999; Scaffold Under Construction in Contact with CV Line/Fitting, March 16, 2004 (NRC Identified)

CR 209638; Scaffold in 2B AF Pump Room Tied Off Inappropriately, March 19, 2004 (NRC Identified)
CR 211387; NRC Concerns on Unit 1; March 28, 2004 (NRC Identified)
CR 211824; Scaffold Built for B1R12 Found Not Removed During B2R11
CR 211906; Potential Negative Scaffolding Program Trend, March 30, 2004
CR 213597; Area 7 Auxiliary Building Scaffold in Contact with 3/4 Inch Line (NRC Identified)
CR 213703; NRC Senior Resident Walkdown Issues, April 6, 2004 (NRC Identified)
CR 213802; Inadequate Corrective Actions - Seismic Scaffold Building
CR 213843; Boric Acid Programmatic Improvements, April 7, 2004
CR 214100; Scaffold B4506 Removed Before C/O 23450 was RTS, April 9, 2004
CR 222036; Deficiencies Identified During NRC Walkdown of Area 5 (NRC Identified)
CR 222804; Scaffold for 0FZ-VCO63C Safety Clearances Issues, May 21, 2004
2004 Corrective Rework Report
2003 Corrective Rework Report
2002 Corrective Rework Report
CAP Trend Analysis Report - Fourth Quarter 2003, Engineering
CAP Trend Analysis Report - Third Quarter 2003, Engineering
CAP Trend Analysis Report - Second Quarter 2003, Engineering
Byron Self Assessment, Second Quarter 2003, Engineering
Byron Self Assessment, Third Quarter 2003, Engineering
Byron Engineering Functional Area Assessment, Fourth Quarter 2002
Byron Engineering Functional Area Assessment, Third Quarter 2002
Byron Station Maintenance Area Assessment, Second Quarter 2003
Byron Self Assessment, Third Quarter 2003, Maintenance
Byron Self Assessment, Fourth Quarter 2003, Maintenance
Maintenance Functional Area Performance, First Quarter 2003
Byron Station Maintenance Assessment, Fourth Quarter 2002
Byron Station Maintenance Assessment, Second Quarter 2002
CAP Trend Analysis Report, First Quarter 2003, Engineering
Byron Station Maintenance Area Assessment, Third Quarter 2002
Permanent Scaffold Request Form, Scaffold Tag No. B4810, B3463, B4917, B712, B714
Byron Self Assessment, Fourth Quarter 2003, Engineering
Interim Corrective Action - Scaffold Erection, Modification and Teardown Activities, Revision 2
MA-AA-716-025; Scaffold Installation, Modification, and Removal Request Process, Revision 0

4OA3 Event Followup

Issue 231943; Entry Into 0BOA ENV-4, Earthquake, Due to Seismic Event, June 28, 2004

Issue 231988; Functionally Check Seismic (EM) Equipment Mounted IN 0PA02J, June 28, 2004

4OA5 Other Activities

ER-AP-335-1012; Visual Examination of PWR Reactor Vessel Head Penetrations; dated September 9, 2003
OP-MA-108-107-1001; Station Response to Grid Capacity Conditions, Revision 0
WC-MW-8003; Interface Agreement Between ComEd Transmission and Substations (T&S) and Exelon Nuclear Generation for Midwest Regional Owners Group (MWROG) Design and Engineering Activities, Revision 1
OP-AA-101-113-1004; Guidelines for the Morning Plant Status Reports, Revision 3
Temporary Operating Order TOO-041204-1-TDa; Voltage Limits for Nuclear Generating Stations, April 23, 2004, Revision 1
Byron Station Design Information Transmittal BYR-04-012; Byron Units 1 & 2 Minimum Switchyard Voltage Requirements and Post-LOCA System Auxiliary Transformer (SAT) Loading, Revision 0
CR 214533; Switchyard Voltage at MWROG Plants, May 7, 2004
CR 219561; Discrepancy Between System Planning Operating Guide (SPOG) 1-1 and UFSAR Operating Voltage, May 7, 2004
SPOG 1-1; Generating Stations Operating Voltage Level, Revision 6, May 15, 2004
SPOG 1-3; Generating Station Stability, Revision 1, May 1, 2000
SPOG 1-3-F; Station 6, Byron Operating Guidelines, Revision 2, May 3, 2001
SPOG 1-3-F-1; Station 6, Byron Operating Guidelines, Revision 2, May 3, 2001
SPOG 2-1; Expected Transmission Voltage Levels at Generating Stations, Revision Annual, Effective Date May 15, 2003, Effective Until June 1, 2004

LIST OF ACRONYMS USED

ADAMS	Agency wide Documents Access and Management System
ALARA	As Low As Reasonable Achievable
ASME	American Society of Mechanical Engineers
BAP	Byron Administrative Procedure
B2R11	Byron Station Unit 2 Refueling Outage Eleven
CFR	Code of Federal Regulations
CR	Condition Report
CV	Chemical and Volume Control System
DRP	Division of Reactor Projects; Region RIII
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling System
ECT	Eddy Current Testing
EDG	Emergency Diesel Generator
EED	Exelon Energy Delivery Systems
EPRI	Electric Power Research Institute
ESF	Engineered Safety Features
ESFAS	Engineered Safety Features Actuation System
GDC	General Design Criterion
IMC	Inspection Manual Chapter
IR	Inspection Report
kV	Thousand Volts
LHP	Lower Head Penetration
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MR	Maintenance Rule
NCV	Non-Cited Violation
NDO	Exelon Nuclear Duty Officer
NPP	Nuclear Power Plant
NRC	United States Nuclear Regulatory Commission
NSP	Nuclear Station Procedure
OPS	Offsite Power Systems
PARS	Publicly Available Records
PI	Performance Indicator
RCS	Reactor Coolant System
RPV	Reactor Pressure Vessel
RTO	Regional Transmission Operator
RWP	Radiation Work Permit
SBO	Station Blackout
SDP	Significance Determination Process
SPOG	System Planning Operating Guide
SSC	System, Structure, and Component
SX	Essential Service Water
TRM	Technical Requirements Manual
TI	Temporary Instruction
TS	Technical Specification

UFMAS	Ultrasonic Flow Measurement System
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item