January 26, 2004

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

SUBJECT: BYRON STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000454/2003007;
05000455/2003007

Dear Mr. Skolds:

On December 31, 2003, 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 January 8, 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 NRC-identified finding of very low safety significance (Green) is identified in the report. In addition, one self-revealed issue was reviewed under the NRC traditional enforcement process and determined to be a Severity Level IV violation of NRC requirements. However, because these violations were of very low significance and because the issues were entered into your corrective action program, the NRC is treating this finding and this issue as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally licensee identified violations are listed in Section 4OA7 of this report.

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, 801 Warrenville Road, Lisle, IL 60532-4351; 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 2.790 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 05000454/2003007; 05000455/2003007
w/Attachment: Supplemental Information

cc w/encl:
Site Vice President - Byron
Byron Station Plant Manager
Regulatory Assurance Manager - Byron
Chief Operating Officer
Senior Vice President - Nuclear Services
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing
Manager Licensing - Braidwood and Byron
Senior Counsel, Nuclear
Document Control Desk - Licensing
Assistant Attorney General
Illinois Department of Nuclear Safety
State Liaison Officer
State Liaison Officer, State of Wisconsin
Chairman, Illinois Commerce Commission

DOCUMENT NAME: C:\ORPCheckout\FileNET\ML040280213.wpd

**To receive a copy of this document, indicate in the box: "C" = Copy without attachment/enclosure "E" = Copy with attachment/enclosure "N" = No copy**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| OFFICE | RIII | | | | | | |
| NAME | AMStone:dtp | | | | | | |
| DATE | 01/26/04 | | | | | | |

***OFFICIAL RECORD COPY***

<u>ADAMS Distribution</u>:
AJM
DFT
GFD
RidsNrrDipmIipb
GEG
HBC
RAS
C. Ariano (hard copy)
C. Pederson, DRS (hard copy - IR's only)
DRPIII
DRSIII
PLB1
JRK1

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

| | |
|---|---|
| Docket Nos: | 50-454; 50-455 |
| License Nos: | NPF-37; NPF-66 |
| Report Nos: | 05000454/2003007; 05000455/2003007 |
| Licensee: | Exelon Generation Company, LLC |
| Facility: | Byron Station, Units 1 and 2 |
| Location: | 4450 N. German Church Road<br>Byron, IL  61010 |
| Dates: | October 1, 2003, through December 31, 2003 |
| Inspectors: | R. Skokowski, Senior Resident Inspector<br>P. Snyder, Resident Inspector<br>R. Alexander, Radiation Specialist<br>P. Higgins, Reactor Engineer<br>P. Lougheed, Engineering Inspector<br>P. Patnaik, Materials Engineer, NRR<br>F. Ramirez, Intern<br>N. Shah, Resident Inspector, Braidwood<br>D. Tharp, Reactor Engineer<br>T. Tongue, Project Engineer<br>C. Thompson, Illinois Department of Nuclear Safety |
| Approved by: | Ann Marie Stone, Chief<br>Branch 3<br>Division of Reactor Projects |

Enclosure

## SUMMARY OF FINDINGS

IR 05000454/2003007; 05000455/2003007; on 10/01/2003-12/31/2003; Byron Station; Units 1 & 2; Operability Evaluations, and Permanent Plant Modifications.

This report covers a 3-month period of baseline resident inspection and announced baseline inspections on radiation protection, heat sink performance and inservice inspection activities. In addition, inspections were conducted using Temporary Instructions (TI) 2515/150, Revision 2; TI 2515/152, Revision 1; and TI 2515/153. The inspection was conducted by Region III inspectors, the resident inspectors, and an NRR inspector. One Severity Level IV Non-Cited Violation (NCV) and one Green finding which was a violation of NRC requirements, were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

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

**Cornerstone: Mitigating Systems**

- Severity Level IV. A finding of very low safety significance was self-revealed when the licensee discovered that an update to the Updated Final Safety Analysis Report was not accomplished for a period of almost 6 years following a design change. Between June and September of 1996, the licensee made a revision to the reactor water storage tank level set-point calculation to clarify design basis information with respect to emergency core cooling system and containment spray system operation and re-evaluated the time available to complete switchover to recirculation. The licensee did not include this update until the December 2002 revision to the Updated Final Safety Analysis Report.

  Because this issue potentially impacted the NRC's ability to perform its regulatory function, this finding was evaluated using the traditional enforcement process. The finding was determined to be of very low safety significance because it did not actually impede or influence any regulatory actions. This was determined to be a Severity Level IV NCV of 10 CFR 50.71. (Section 1R17)

**Cornerstone: Barrier Integrity**

- Green. A finding of very low safety significance and associated NCV was identified by the inspectors for the licensee's failure to identify and correct a condition adverse to quality. Specifically, the licensee failed to recognize that the containment atmosphere radiation gaseous monitors were inoperable when it was determined that the monitors were not capable of detecting reactor coolant leakage in a reasonable period of time. The finding also affected the cross-cutting area of Problem Identification and Resolution because although the issue was discovered by the licensee's staff, they failed to recognize the significance of the issue until questioned by the NRC inspectors.

The finding was greater than minor because the finding was associated with the barrier integrity cornerstone and, if left uncorrected, could result in an undetected reactor coolant system leak.  The finding was determined to be of very low safety significance by management review because alternate methods of detecting small reactor coolant system leaks were available.  To correct the immediate issue, the licensee declared the monitor inoperable and submitted a Technical Specification change.  This issue was a NCV of 10 CFR 50 Appendix B Criteria XVI, “Corrective Action.”  (Section 1R15)

## B. Licensee Identified Violations

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

# REPORT DETAILS

## Summary of Plant Status

Unit 1 began the inspection period shut down for a refueling outage. On October 12, 2003, restart activities began with the unit reaching full power on October 16, 2002. The unit operated at or near full power for the remainder of the inspection period.

Unit 2 operated at or near full power throughout the inspection period.

## 1. REACTOR SAFETY

### Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors completed a total of two samples in this area. The inspectors completed one inspection sample with their review of the licensee's response to sustained high winds on November 12, 2003. 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 inspectors completed the second sample when they evaluated the licensee's preparation for adverse weather conditions during the winter months (i.e., below freezing temperatures and accumulation of ice and snow), which could potentially lead to a loss of offsite power or a loss of mitigating systems. The inspectors walked down the river screen house, primary water storage tanks, reactor water storage tanks (RWST), and other areas of the station potentially affected by cold weather to inspect insulated and trace heated piping and components, operation of area space heaters, and closure of outside air dampers. The inspectors selected the river screen house and the storage tanks listed because they were either identified as risk significant in the licensee's risk analysis or had experienced problems with freezing and/or leaf accumulation in the past year. The inspectors interviewed operations department personnel and reviewed applicable portions of the Updated Final Safety Analysis Report (UFSAR). The inspectors evaluated licensee performance by comparing actual performance to the licensee management expectations and guidelines as presented in Byron Abnormal Operating Procedures. The following references were used:

- NSP OP-AA-108-109; Seasonal Readiness, Revision 1; and
- BOP XFT-1; Cold Weather Operations, Revision 1.

In addition, the inspectors reviewed the issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance. The inspectors also reviewed the licensee's corrective actions for cold weather related issues documented in selected condition reports (CRs). 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.

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdowns

a. Inspection Scope

The inspectors performed two 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 to determine the functional requirements of the systems.

The inspectors verified the alignment of the following trains:

- Unit 1 and Unit 2 125 volts direct current distribution systems during the battery charger 112 work window requiring the cross connection of direct current (DC) buses 112 and 212; and
- Unit 1 train A and C of the feedwater system while train B was out-of-service for maintenance.

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

- BOP FW-M2; Main Feedwater System Valve Lineup, Revision 12;
- BOP DC-E1, Unit 1 DC Battery and Distribution Center Electrical Lineup, Revision 10; and
- BOP DC-E2, Unit 2 DC Battery and Distribution Electrical Lineup, Revision 7.

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.

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

During the Unit 1 refueling outage the inspectors finished one complete system alignment inspection of the Unit 1 emergency core cooling system (ECCS) portions inside containment. This system was selected because it was considered both safety related and risk significant in the licensee's probabilistic risk assessment. 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 operator workarounds to determine applicability to the emergency core cooling system;
- 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 utilized the following references during the completion of their review:

- BOP RH-11, Securing the RH System from Shutdown Cooling, Revision 17;
- 1BGP 100-1, Plant Heatup, Revision 40;
- Reactor Building Piping Plan Elevation 377'-0", Drawing Number M-155;
- Reactor Building Piping Plan Elevation 401'-0", Drawing Number M-161;
- Reactor Building Piping Plan Elevation 412'-0", Drawing Number M-165;
- BOP SI-M1, Safety Injection System Valve Lineup, Revision 16;
- BOP SI-E1, Safety Injection System Unit 1 Electrical Lineup, Revision 7;
- BOP RH-E1, Residual Heat Removal System Unit 1 Electrical Lineup, Revision 3;
- BOP RH-M1, Residual Heat Removal System Valve Lineup, Revision 13;
- BOP CV-E1, Unit 1 Chemical and Volume Control Electrical Lineup, Revision 7; and
- BOP CV-M1, Unit 1 Chemical and Volume Control System Valve Lineup, Revision 26.

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.

b. 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. The inspectors used the following reference documents:

- Fire Test TR-207; Fire and Hose Stream Test of an Empty Embedded Steel Sleeve and Plugs (each end) and an Embedded Steel Conduit Filled with 5.0' (max.) #TCO-010 Ceramic Blanket and Steel Plugs at Each End, May 1, 1985; and
- Fire Test TR-110; Transco Test Report TR-110 Fire and Hose Stream Test of TCO-003 High Density Silicone Elastomer, April 22, 1983.

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 at the end of this report were also used by the inspectors to evaluate this area.

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

- Unit 1 Division 11 four kilovolt switchgear room (Zone 5.2-1);
- Unit 1 and Unit 2 auxiliary building general area, elevation 426 (Zone 11.6-0);
- Unit 1 Division 11 miscellaneous electrical equipment room (Zone 5.6-1);
- Auxiliary building general area 346 foot elevation (Zone 11.2-0);
- Unit 2 Division 21 miscellaneous electrical equipment room and battery room (Zone 5.6-2);
- Unit 2 Division 22 engineered safety features switchgear room (Zone 5.1-2); and
- Unit 2 Division 22 miscellaneous electrical equipment room and battery room (Zone 5.4-2).

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.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.HS)

.1 Biennial Review of Heat Sink Performance

a. Inspection Scope

A specialist inspector reviewed documents associated with the component cooling water heat exchangers and the residual heat removal heat exchangers. These heat exchangers were chosen for review based on their high risk assessment worth in the licensee’s probabilistic safety analysis. The residual heat removal heat exchangers were additionally chosen because they were indirectly connected to the essential service water system such that the procedural provisions for indirectly connected heat exchangers were reviewed. The inspection was conducted from December 9 - 12, 2003, at the site. While on site, the inspector reviewed the results of licensee inspections and examined eddy current test results for the component cooling water heat exchangers. The eddy current results were compared to the licensee's acceptance criteria for tube plugging. The inspector also held discussions with licensee personnel regarding chemical controls in place that would detect leakage from the residual heat removal heat exchangers, and procedural controls that would detect or prevent the formation of air bubbles which could result in pressure transients occurring. The inspector reviewed the documentation to confirm that the inspection methodology was consistent with accepted industry and scientific practices. The inspector performed a field walkdown of the three component cooling water heat exchanger essential service water valves to review the valve position as a potential indicator of heat exchanger fouling.

The inspector reviewed corrective action documents concerning heat exchanger or heat sink performance issues to verify that the licensee had an appropriate threshold for identifying issues. The inspector also evaluated the effectiveness of the corrective actions for identified issues, including the engineering justification for operability, if applicable. The inspector specifically reviewed the issues of essential service water pitting and corrosion, and heat exchanger coating adherence to determine the adequacy of the licensee’s corrective actions.

The documents that were reviewed are included at the end of the report.

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 reactor coolant system boundary and the risk significant piping system boundaries.

Specifically, the inspectors conducted an onsite record review of the following six 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. 1RC21AB-8-inch-J07 (pipe-elbow);
- Ultrasonic Examination of Weld No. 1RC21AB-8-inch-J08 (elbow-pipe);
- Ultrasonic Examination of Weld No. 1RC21AB-8-inch-J10 (elbow-pipe);
- Ultrasonic Examination of Weld No. 1FW81BD-6-inch, Component Nos. C03-C06;
- Visual Examination of Unit 1 Reactor Pressure Vessel Lower Head Penetrations; and
- Visual Examination of Unit 1 Reactor Pressure Vessel Upper Head Penetrations.

The inspectors determined that there were no recordable indications identified from the previous outage examinations which had been accepted by the licensee for continued service in accordance with the ASME Code. Therefore, an inspection sample could not be completed.

The inspectors also determined that there were no pressure boundary welds for Class 1 or 2 systems which were completed since the beginning of the previous refueling outage. Therefore, an inspection sample could not be completed.

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

- Work Order Package 99218401-10; Replacement of Valves 1MS 020A, 1MS 021A, and Pipe 1MS 20AA in the Main Steam Tunnel;
- Work Order Package 00599592-01; Replacement of Valve 1CV 8384B in 1B Seal Injection Filter Inlet Isolation Line; and
- Work Order Package 00469595-08; Repair of Upper Stationary Channel Head in 1B Diesel Generator Jacket Water Upper Cooler.

The inspectors reviewed a sample of inservice inspection related problems documented in the licensee’s corrective action program to assess conformance with Title 10 of the Code of Federal Regulations (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 determined that the licensee was not required to and did not inspect the Unit 1 steam generators during this outage; therefore, no steam generator related activities could be inspected. This review could not be counted as a sample.

b. <u>Findings</u>

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On November 10, 2003, 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 03-06-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 2, and
- OP-AA-104-101, Communications, 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 INST-2, Operation with a Failed Instrument Channel, Revision 103;
- 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)

### a. Inspection Scope

The inspectors completed three 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:

- control rod system function of motion for reactivity control and shutdown;
- essential service water cooling tower fans; and
- control room ventilation system.

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 each system, structure, and component (SSC) reviewed, the inspectors also reviewed the significant work orders and condition reports listed in the Attachment at the end of 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; and
- NUMARC 93-01, Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2.

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.

### 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, Technical Specifications (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 at the end of 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 7;
- NSP ER-AA-600, Risk Management, Revision 3;
- NSP ER-AA-310, Implementation of the Maintenance Rule, Revision 2; and
- Byron Operating Department Policy 400-47, August 15, 2003, Revision 3.

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

- Unit 2 train B auxiliary feedwater pump emergent unavailability due to lube oil leak; and
- Unit 1 train A centrifugal charging pump unavailable concurrent with the Unit 1 station auxiliary transformer.

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:

- Unit 1 startup following Byron Station Unit 1 Refueling Outage Twelve (B1R12).

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-103-104, Reactivity Management Controls, Revision 2; and
- OP-AA-104-101, Communications, Revision 1.

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 five inspection samples by reviewing the following evaluations and issues:

- The licensee's justification for not correcting existing degrading and nonconforming conditions during B1R12;
- Operability Determination 03-006, Instrument Degraded Voltage Value Below Manufacturer's Minimum;
- Engineering Change Analysis 342009, Evaluation of ECCS Leakage External to Containment;
- Operability Determination 03-007, Improper Installation of Engineering Change 340158, Essential Service Water Cooling Tower Oil Sample Line; and
- Condition Report 188079 on Unit 2 train A centrifugal charging pump room unit cooler flow past operability.

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 0. 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;
- NRC Generic Letter No 91-18: Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions, Revision 1; and
- Institute of Electrical and Electronics Engineers Standard 308: Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations.

In addition, the inspectors reviewed information associated with Unresolved Item 50-454/455-02-02-02, Non-Conservative Error in PR11J Setpoint Analysis. This review was not considered an inspection sample.

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.

b. Findings

No findings of significance were identified as a result of the inspections performed this quarter. However, during review of the operability determination associated with degraded voltage, a licensee identified violation was noted and was described in Section 4OA7 of this report. In addition, one finding was identified during the closure of Unresolved Item 50-454/455-02-02-02, Non-Conservative Error in PR11J Setpoint Analysis.

Introduction

The inspectors identified a Non-Cited Violation (NCV) of Criteria XVI of 10 CFR 50 Appendix B having very low safety significance (Green) for failing to identify and correct a condition adverse to quality. Specifically, the licensee failed to recognize that the containment atmosphere radiation gaseous monitors were inoperable.

Description

In January 2002, the licensee documented in CR 89364 that during a review of the setpoint for containment atmosphere radiation monitors (1/2PR11J), a non-conservative error was found. The reactor coolant system (RCS) activities used to calculate the 1 gallon per minute (gpm) leak rate were substantially more than the existing RCS activities. This error affected the monitor's ability to detect a one gpm leak from the RCS within 1 hour. For example, the assumed Xe-135 concentration was 1.26 curies per gram (Ci/gm) and the actual [concentration] was 1.30 E-3 Ci/gm which was roughly a factor of one thousand lower. The licensee immediately evaluated the condition and in CR 89583, stated that there was no operability concern because the monitors met the TS surveillance requirements; however, additional review was necessary.

Regulatory Guide 1.45 "Reactor Coolant Pressure Boundary Leakage Detection Systems," stated that, "In analyzing the sensitivity of leak detection systems...a realistic primary coolant radioactivity concentration assumption should be used. The expected values used in the plant environmental report would be acceptable." As stated in the

UFSAR, Appendix A, the licensee was committed to Regulatory Guide 1.45, with the caveat that leak detector sensitivity was as low as practicable. The licensee confirmed that the radiation monitor setpoints were not based on actual RCS activity values but were realistic RCS activities as allowed by Regulatory Guide 1.45. The licensee also stated that the monitors were of original equipment and that no modifications were done to change the characteristics of the detectors. The licensee concluded that the particulate and gaseous monitors were operable because the monitors met their design basis and could detect a one gpm leakage within 1 hour at the reactor coolant activities specified in the plant environmental report. The licensee planned to clarify the TS bases and UFSAR to reflect the actual capabilities of the monitors and define other available means to detect leakage.

The inspectors noted that TS 3.4.15 required either the gaseous or particulate containment atmosphere radioactivity monitor be operable. The bases for this TS states, in part, that "radioactivity detection systems shall be operable to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the unit in a safe condition, when RCS leakage indicated a possible reactor coolant pressure boundary degradation." The bases for another Technical Specification, TS 3.4.13, further stated that 1 gallon per minute of unidentified leakage was allowed as a reasonable minimum detectable amount that the containment air monitoring system could detect within a reasonable time period. The inspectors questioned whether the 1/2PR11J containment atmosphere radiation monitors were technically operable because at current activity levels, a 1 gpm RCS leakage would be detected by the gaseous containment atmosphere radiation monitors in 223 to 839 hours. The inspectors opened the unresolved item pending further review by the NRC Office of Nuclear Reactor Regulation.

On February 20, 2003, the NRC concluded that the gaseous monitor sensitivity did not meet the bases for TS 3.4.13 and therefore, was not sufficient to support the leak before break monitoring assumptions. The licensee declared the gaseous monitors inoperable. In a letter dated August 15, 2003, the licensee requested an amendment to TS 3.4.15, to remove reference to the gaseous monitor and provided justification to the operability of the particulate monitor. At the issuance of this inspection report, this amendment in the review process.

Analysis: The inspectors determined that failing to identify that the containment atmosphere radiation gaseous monitors were inoperable 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." The inspectors concluded that the issue was more than minor because it was associated with RCS barrier integrity and if left uncorrected, could result in an undetected reactor coolant system leak. The finding also affected the cross-cutting area of Problem Identification and Resolution because although the issue was discovered by the licensee's staff, it was not adequately resolved until questioned by the NRC 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," because the SDP for the RCS barrier only applied to a degraded barrier, not the ability to detect a degraded barrier. 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 alternate methods of detecting small RCS leaks were available and no actual leak had occurred. The finding was assigned to the barrier integrity 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 non-conformances are promptly identified. Contrary to the above, in January 2002, the licensee failed to identify that the gaseous containment atmosphere radiation monitors were inoperable when the licensee determined that the monitors were not capable of detecting a one gpm leak within 1 hour or a reasonable period of time as specified in TS bases 3.4.15 and 3.4.13. This violation was in the licensee's corrective action program as CR 195150. 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 05000454/2003007-01; 05000455/2003007-01). Unresolved Item 50-454/455-02-02-02, Non-Conservative Error in PR11J Setpoint Analysis, is now closed.

## 1R16 Operator Workarounds (71111.16)

### a. Inspection Scope

The inspectors performed one semi-annual review sample of the licensee's operator workarounds to verify that the cumulative effects of operator workarounds and operator challenges did not adversely impact the ability to operate the plant. In particular, the inspectors focused on the following attributes:

- the cumulative effects of operator workarounds on the reliability, availability and potential for missed operation of a system;
- the cumulative effects of operator workarounds that could affect multiple mitigating systems; and
- the cumulative effects of operator workarounds on the ability of operators to respond in a correct and timely manner to plant transients and accidents.

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 did not complete an inspection sample in this area. The inspectors did review selected issues documented in CRs, to determine if they had been properly addressed in the licensee's corrective action program. The documents reviewed during this inspection were listed in the Attachment to this report.

b. Findings

Introduction: A self-revealed finding was identified for failure to update the UFSAR in a timely manner as required by 10 CFR 50.71(e). The issue was considered to be of very low safety significance and was dispositioned as a Severity Level IV NCV.

Description: Between June and September 1996, the licensee made a change to the facility as described in the UFSAR. The RWST level set-point calculation was revised to clarify design basis information with respect to ECCS and Containment Spray operation and the time available to complete switchover to recirculation was re-evaluated. In August 1996, the licensee initiated Draft Revision Package 6-072 to update the UFSAR. However, the update to the UFSAR was not completed until Revision 9 was incorporated in December 2002 because Draft Revision Package 6-072 was not approved until March 1998 by Byron Station and August 2002 by Braidwood.

The inspectors noted that during this 6-year period in which Draft Revision Package 6-072 was in review, and the UFSAR was not updated, analyses performed for subsequent changes may have been impacted. This could result in incomplete or inaccurate analyses for these changes and unknown safety concerns may exist. The licensee reviewed all the changes made to the facility during this period and found that none of these changes were affected by Draft Revision Package 6-072.

Analysis: The inspectors determined that failing to update the UFSAR was a performance deficiency because it is required by 10 CFR 50.71. Because this finding potentially impacts the NRC's ability to perform its regulatory function, it was dispositioned using the traditional enforcement process. Based on the guidance provided in Sections IV.A.3 and IX of the NRC's Enforcement Policy, NUREG-1600, the inspectors determined the violation to be of Severity Level IV. The inspectors made this determination based on the low safety significance of the issue, the fact that it did not actually impede or influence any regulatory actions, and it did not meet the criteria for a Severity Level I, II, or III violation listed in Supplement VII of the Enforcement Policy.

Enforcement: Part 50.71(e) of 10 CFR states, in part, that the licensee shall update periodically the final safety analysis report and that revisions must be filed annually or 6 months after each refueling outage provided the interval between successive updates does not exceed 24 months. The revisions must reflect all changes up to a maximum of 6 months prior to the date of filing. Contrary to this, the licensee completed a plant modification in September 1996 and failed to update the UFSAR until December 2002. The result of the violation was determined to be of very low safety significance; therefore, this violation of 10 CFR 50.71 was classified as a Severity Level IV violation. The licensee entered the issue into their corrective action program as CR 189358. This Severity Level IV violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000454/2003007-02; 05000455/2003007-02).

## 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 at the end of 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 0.

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

- Unit 1 train A centrifugal charging pump following seal replacement;
- Unit 1 train A essential service water pump following pump overhaul;
- Unit 1 pressurizer relief tank primary water supply containment isolation valve following repair for seal leakage;
- Unit 1 train A centrifugal charging pump following the loss of gear box lube oil pressure;
- Unit 1 train A emergency diesel generator following maintenance activities;
- Unit 1 reactor coolant pump D following electric motor overhaul; and
- Unit 1 pressurizer power operated relief valve 1RY455A following repair for seat leakage.

### 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 B1R12 beginning September 23, 2003, and concluding on October 14, 2003. The inspection activities described below complete 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 core loading plan CAC-03-75 for Byron Unit 1 Cycle 13;
- 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.

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

b. Findings

No findings of significance were identified. However, on October 1, 2003, a special inspection was initiated to examined the facts and circumstances surrounding a Unit 1 fuel handling incident on September 26, 2003, where the mast of the fuel handling machine made contact with the rod cluster control assembly change fixture basket in the fuel transfer cavity. The details of that inspection are documented in Inspection Report 05000454/2003008.

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 used the documents listed in the Attachment at the end of 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.

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

- Unit 1 visual inspection of the emergency core cooling system recirculation sump, completed on October 7, 2003; and
- Unit 1 summation of primary containment local leakage tests.

The inspectors also reviewed selected issued 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.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

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

- Engineering Change 345559, leak repair of leaking pipe cap down steam of valve 1CV065A.

The inspectors reviewed this temporary plant modification 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 verified that the licensee controlled temporary modifications in accordance with Procedure NSP CC-AA-112, "Temporary Configuration Changes," Revision 6.

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

- NSP CC-AA-404; Maintenance Specification: Application Selection, Evaluation and Control of Temporary Leak Repairs, Revision 5; and
- NRC Generic Letter 90-05, Guidance for Preforming Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping, June 15, 1990.

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

b. Findings

No findings of significance were identified

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

On October 22, 2003, the inspectors complete one inspection sample by observing an Emergency Preparedness Exercise. The inspectors assessed the licensee's exercise performance and looked for weaknesses in the risk significance areas of emergency classification, notification and protective action development. The inspectors observed the licensee's performance from the simulator control room and from the technical support center. The inspectors compared issues noted during their observations to those identified during the licensee's critique as contained in the licensee's exercise findings and observation report. Additionally, the inspectors verified that items identified during the licensee's critique were appropriately entered into their corrective action program. The inspectors utilized the following references during the completion of their review:

- NPS EP-MW-114-100, Midwest Region Offsite Notification, Revision 3;
- NPS EE-AA-111, Emergency Classification and Protective Action Recommendations, Revision 7; and
- NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 2.

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

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

- Unit 1 Containment (Inside and Outside Missile Barrier);
- Auxiliary Building; and
- Radioactive Waste Building.

The inspectors reviewed the radiation work permits (RWP) and work packages used to control work in these three 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 verify that they were aware of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed.

The inspectors walked down these three areas to verify that the prescribed RWP, procedure, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers (if necessary) were properly located. In particular, the inspectors surveyed selected areas within the Radioactive Waste Building (using an NRC survey meter) to corroborate the radiation measurements documented on the survey maps for the areas.

The inspectors reviewed the RWP for the upper internals lift activities in the Unit 1 reactor cavity which had the potential for creating an airborne radioactivity area. The inspectors reviewed the RWP to verify barrier integrity and engineering control contingency plans were in place and to determine if there was a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent. This and other work activities/areas having a history of, or the potential for, airborne transuranic isotopes were evaluated to verify that the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection.

The inspectors also reviewed the licensee's physical and programmatic controls for highly activated and/or contaminated materials (non-fuel) stored within spent fuel pool.

These reviews represented five inspection samples.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed nine corrective action reports related to access controls written during the most recent Unit 1 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.

The inspectors evaluated the licensee's process for problem identification, characterization, prioritization, and verified that problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution, the inspectors verified that the licensee's self-assessment activities were capable of identifying and addressing these deficiencies.

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 two jobs 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:

- Fuel Transfer Canal Diving Activities (RWP No. 10003532); and
- Completion of Upper Internals Reinstallation Activities (RWP No. 10002424).

The inspectors reviewed radiological job requirements for these two 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 fuel transfer canal diving activities involved areas where the dose rate gradients were severe which increased the necessity of providing multiple dosimeters and/or enhanced job controls.

These reviews represented two 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 had 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 performance 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 ALARA Planning And Controls (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective exposure history, current exposure trends, ongoing and planned activities in order to assess current performance and exposure challenges. This included determining the plant's current 3-year rolling average for collective exposure in order to help establish resource allocations and to provide a perspective of significance for any resulting inspection finding assessment. The inspectors reviewed the Unit 1 outage work scheduled during the inspection period and associated work activity exposure estimates for the following five work activities which were likely to result in the highest personnel collective exposures:

- Miscellaneous Air Operated Valve Work (RWP No. 10002419);
- Reactor Head Component Disassembly and Reassembly (RWP No. 10002421);
- Reactor Coolant Pump Inspections, Maintenance and Repairs (RWP No. 10002427);
- Reactor Cavity Decontamination Activities (RWP No. 10002443); and
- Scaffold Staging, Building and Removal (RWP No. 10002448).

These reviews represented two inspection samples.

b. Findings

No findings of significance were identified.

.2 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.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolutions

a. Inspection Scope

The inspectors reviewed licensee self-assessments, audits, and Special Reports related to the ALARA program since the last inspection to determine if the licensee's overall audit program's scope and frequency for all applicable areas under the Occupational Cornerstone met the requirements of 10 CFR 20.1101(c). In particular, the inspectors' reviews included the licensee's Radiation Protection Department Unit 1 outage readiness self-assessment and Nuclear Oversight field observations related to the ongoing outage.

The licensee's corrective action program was also reviewed to determine if repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution (with respect to ALARA planning and controls) had been addressed.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

## 4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

**Cornerstone: Mitigating Systems**

.1 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensees 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 were reviewed:

Unit 1

- safety system unavailability for the auxiliary feedwater system (July 2002 through June 2003); and

- safety system unavailability for emergency AC power (July 2002 through June 2003).

Unit 2

- safety system unavailability for the auxiliary feedwater system (July 2002 through June 2003); and
- safety system unavailability for emergency AC power (July 2002 through June 2003).

The inspectors reviewed selected applicable conditions and data from logs, licensee event reports and CRs from July 2002 through June 2003 for each PI area specified above. The inspectors independently reperformed calculations where applicable. The inspectors compared that information to the information required for per each performance indicator definition in the guideline to ensure that the licensee reported the data accurately.

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 Corrective Actions Associated with a Confirmatory Order (Annual Sample)

Introduction

On October 3, 2002, the NRC issued a Confirmatory Order to the Exelon Corporation regarding discrimination of a licensee employee for raising safety concerns. Since this Order described actions particular to the Byron Station, the inspectors reviewed the licensee's corrective actions as they applied to the Byron Station. This review represented one annual inspection sample of identification and resolution of problems.

a. <u>Effectiveness of Corrective Actions</u>

(1) <u>Inspection Scope</u>

The inspectors reviewed the Byron Station Actions taken in response to the Confirmatory Order dated October 3, 2002, regarding discrimination of a licensee employee for raising safety concerns. Specifically, the inspectors performed the following:

- verified that all required supervisors and managers received the training;
- attended and assessed the training regarding the Order completed on March 6, 2003; and
- assessed, via interviews, the understanding of the supervisors and managers regarding the training provided.

In addition, the inspectors reviewed the licensee's survey results and other information regarding the safety conscious work environment at the Byron Station developed since September 2000. During the review, the inspectors focused on the actions taken by the licensee to address concerns associated with the Byron Station safety conscious work environment.

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

(2) <u>Issues</u>

A review of training attendance sheets and the licensee's organization charts indicated that all the appropriate supervisors and managers were trained. Based on the inspectors observations of the March 6, 2003, training session and the interviews of selected supervisors and managers, the inspectors determined the message presented by the training was understood.

Based on the results of the licensee's survey results and other information regarding the safety conscious work environment at the Byron Station, the licensee noted two concerns that were in need of corrective actions.

- First, the February 2001 assessment noted that 28 percent of the population interviewed believed that during outage periods, production and schedule adherence took precedence over safety, and that 7 percent of the population interviewed believed production always was given a higher priority than safety. In response to this issue, the licensee had been emphasizing that safety took precedence over production through various meetings and briefings. At the briefings and meeting, which includes outage meetings, shift turnover briefings and outage control center status briefings, the first issue discussed was to be safety. The inspectors frequently observed station meetings and briefings and noted that safety was generally the first topic discussed. Additionally, during these meeting and briefings, the inspectors routinely observed that the emphasis was placed on safety, and that it was clearly stated that there was not to be schedule pressure associated with the activities.

- Second, based on a review of referred allegations completed in 2001, the licensee identified a need to improve overall site communications, including vertical communications, as well as, increasing senior managements' visibility. As a result, the Site Vice President and/or Plant Manager started holding monthly employee feedback meetings, as well as a quarterly meeting with each department to solicit employee feedback on current station issues.

The licensee did not identify a concern with assessment of the safety conscious work environment at the Byron Station. In addition, based on the licensee's assessment, there was no indication that discrimination issues associated with the Confirmatory Order had a residual effect on the employee's willingness to raise safety issues. However, the licensee identified that other work environment and employee relation issues warranted further licensee management attention.

As documented in the Problem Identification and Resolution (PI&R) Inspection Report 05000454/2003009(DRP); 05000455/2003009(DRP), the PI&R team interviewed approximately 48 members of the plant staff, representing all major work groups, and all levels of responsibility. The team conducted the interviews to assess the establishment of a safety conscious work environment. During the interviews, document reviews, and observations of activities, the team looked for evidence that plant employees might be reluctant to raise safety concerns. The interviews typically included questions similar to those listed in Appendix 1 of NRC Inspection Procedure 71152, "Suggested Questions for Use in Discussions with Licensee Individuals Concerning PI&R Issues." The team also reviewed the station's procedures related to the Employee Concerns Program (ECP), and discussed the implementation of this program with the station's program coordinator.

No significant findings were identified. None of the plant personnel interviewed expressed any concerns regarding a safety conscious work environment. All plant personnel interviewed stated that individuals were encouraged by managers and supervisors to identify issues. Personnel were aware of the ECP, ECP office location, and the ECP coordinators. The team noted no reluctance on the part of plant personnel that were interviewed to use the ECP. Trends of ECP usage by employees showed a slight upward trend of the previous 3 years.

Some employees expressed concerns with staffing and work assignments at the Byron plant, which are not issues the corrective action program was designed to address. With many work groups reduced in size over the past couple of years, increased work for all the remaining staff was said to potentially risk more errors and to reduce the time available for tasks such as administering functions of the corrective action program. However, no one identified an example of staff inability or unwillingness to raise and document safety concerns due to inadequate time or resources.

4OA3 Event Follow-up (71153)

.1 Indications of Fuel Pin Leak on Unit 1

a. Inspection Scope

After startup from the refueling outage, the licensee noted an increasing trend in Unit 1 RCS activity. On October 17, 2003, the licensee entered Abnormal Operating Procedure 1BOA PR-4, "Abnormal Primary Chemistry," due to an alert alarm received on the gross failed fuel monitor. Based on these indications of a potential fuel pin leak, the licensee established a Failed Fuel Monitoring Team, increased RCS sampling frequency, and took other actions in accordance with the abnormal operating procedure. The inspectors monitored RCS sample results and actions taken by the monitoring team, including the development of contingencies and power maneuvering plans. A review of RCS sample results showed that iodine and xenon activity had been increasing since about October 17 and continued to increase until October 30, when they began to stabilize. The inspectors verified that the RCS activity levels never approached TS limits, although they were between one and two decades above the values from before the outage. Documents reviewed as part of this inspection were listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 (Closed) Licensee Event Report (LER) 05000454/2003003-00; 05000455/2003003-00: "Licensed Maximum Power Level Exceeded Due to Inaccuracies in Feedwater Ultrasonic Flow Measurements Caused by Signal Noise Contamination." On August 28, 2003, the licensee determined 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 for determining reactor power. Investigation by the licensee, with support from the UFMS vendor, determined that signal noise adversely impacted the ability of the UFMS to accurately calculated feedwater flow.

The licensee reviewed the power history to determine the worst case power level for each of the Byron units since the installation of the UFMS. Based on the review, the licensee determined that, when compared to the original feedwater flow instrument the worst case power level was 102.62 percent for Unit 1 and 101.88 percent for Unit 2. However, the licensee's position was that ultrasonic flow instrument installed on the common header provided a more accurate indication of feedwater flow, and therefore it should be used instead of the original feedwater flow instrument to determine worst power levels. This resulted in worst case levels of 101.64 percent for Unit 1 and 100.47 percent for Unit 2. 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 URI 50-454/03-02-03.

.3 (Closed) LER 50-454/2003-004-00: "Two Main Steam Safety Valves Lift Setpoints Found Out of Tolerance During Testing Due to Unknown Causes." On September 16, 2003, the licensee identified two of 20 main steam safety valves (MSSV) on Unit 1 failed to meet TS limit of 3 percent of lift pressure during surveillance testing. After identifying each test failure, the licensee entered into the appropriate TS limiting condition for operation, adjusted the MSSV setpoint, and retested the valve satisfactorily within the TS allowed outage time. The licensee evaluated the impact on the two MSSVs being out of tolerance and concluded that the condition was bounded by the safety analysis report. The inspectors reviewed and concurred with the licensee's evaluation. In addition, the licensee was investigating the cause of the failures and will submit a supplement to the LER. The inspectors determined that the issue has greater significance than a similar issue described in IMC 0612, "Power Reactor Inspection Reports," Appendix E Section 2.a. This licensee-identified issue involved a violation of TS 3.7.a, Main Steam Safety Valves. The enforcement aspects of this issue were discussed in Section 4OA7. This LER is closed.

## 4OA4 Cross-Cutting Aspects of Findings

.1 A finding identified in Section 1R15 of this report had as its primary cause a problem identification and resolution deficiency. The licensee identified that a non-conservative error existed in the Unit 1 and Unit 2 PR11J containment gaseous radiation monitors setpoint analysis such that the monitor could not detect a one gpm leak from the RCS in 1 hour. However, the licensee failed to recognize that the detectors were inoperable without additional questions being asked by the NRC inspectors.

## 4OA5 Other Activities

### .1 Reactor Pressure Vessel (RPV) Head and Vessel Head Penetration Nozzles (VHP) (TI 2515/150, Revision 2)

#### a. Inspection Scope

The inspectors conducted a review of the licensee's activities in response to the requirements of Order EA-03-009, "Issuance of Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors

(PWR)," (NRC ADAMS Accession Number ML030410402), issued on February 11, 2003. To support the evaluation of the licensees' activities implemented in accordance with Order EA-03-009, TI 2515/150, Revision 2, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Order EA-03-009)," was issued August 4, 2003.

For Unit 1, the licensee's effective degradation years (EDY) calculation of 2.0 placed the Unit in the primary water stress corrosion cracking susceptibility category of "Low" (plants with a calculated value of EDY less than 8, with no previous inspection findings requiring classification as High). Based on the "Low" category the licensee performed a bare metal visual examination of 100 percent of the RPV head surface (including 360 degrees around each RPV head penetration nozzle) during this refueling outage.

Summary

The licensee did not identify any leaking vessel head penetration nozzles.

b. Evaluation of Inspection Requirements

In accordance with requirements of TI 2515/150, Revision 2, 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?

Yes. The inspectors verified through review of the certification records that the remote bare metal visual examination of the RPV head was performed by qualified and certified Level II and Level III VT-2 examiners. Examination personnel also received instruction on Electric Power Research Institute (EPRI) Report TR 1000975, "Boric Acid Corrosion Evaluation."

2. Performed in accordance with demonstrated procedures?

Yes. The remote bare metal visual examinations were conducted in accordance with Nondestructive Examination ER-AP-335-1012, Revision 0, "Visual Examination of PWR Reactor Vessel Head Penetrations." Lighting and resolution capabilities were demonstrated by the capability of the remote camera system to resolve color and 0.158 inch high lower case characters from 24 inches. Nevertheless, the resolution approached 0.044 inch lower case characters at distances under 12 inches under available lighting. Overall, the inspectors considered that the quality of the remote visual examination was excellent based on the ability to resolve the 0.044 inch lower case characters and very small debris at the VHP nozzle-to-head interfaces. The inspectors noted during review of licensee's procedure ER-AP-335-1012, Revision 0, "Visual Examination of PWR Reactor Vessel Head Penetrations," that Paragraph 2.1, "Material and Special Equipment," did not specify the resolution capability of the visual aids and the equipment used in performing the remote visual examination. However, the resolution capabilities far exceeded the minimum industry standards.

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

Yes. The inspectors verified that the licensee was able to identify deficiencies through review of the videotape documentation. The inspectors found no evidence of penetration leakage or boric acid accumulation.

4. Capable of identifying the primary water stress corrosion cracking (PWSCC) and/or RPV head corrosion phenomena described in Order EA-03-009?

Yes. The inspectors verified through interviews with examination personnel and review of the video records of the reactor head surface and penetration nozzle examinations that the licensee's efforts were capable of detecting and characterizing PWSCC and/or RPV head corrosion phenomena described in NRC Order EA-03-009.

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

The Unit 1 RPV head insulation consisted of mirror panels with access doors in the service structure. Through discussions with inspection personnel and viewing of the videotape documentation, the inspectors determined that the as-found pressure vessel head condition was relatively clean with no viewing obstructions. Very small debris at the VHP nozzle-to-head interfaces was noted; however, this did not obstruct the exam. The licensee's inspection personnel fully examined the VHPs. There were no indications of vessel head penetration nozzle leakage and no boric acid buildup deposits were observed on the reactor vessel head. However, residue staining from inactive leaks, originating from above the head, could be seen on the following five nozzles: #21, #66, #68, #78 and #77. The locations correspond to core exit thermocouple nozzle assemblies which had previously leaked. Replacement of the assemblies with a modified design was planned. The licensee documented the leakage in CR 178059, "Boron Residue Collecting on Vessel Head Penetrations." At the conclusion of the inspection, the licensee vacuum cleaned the residue and other debris from the head.

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

Yes. The inspectors reviewed the videotape of the licensee's demonstration of visual resolution and determined that it was consistent with the procedure requirements. The video quality provided a superior inspection to that available from a direct visual examination conducted from the access doors in the service structure. The inspectors considered that the quality of the remote visual examination was excellent based on the ability to resolve 0.044 inch lower case characters and very small debris at the VHP nozzle-to-head interfaces

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

None. The remote bare metal visual inspections of 100 percent of the RPV head surface (including 360 degrees around each RPV head penetration nozzle) did not identify any material deficiencies that required repair.

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

None. The inspectors verified that, there were no impediments to the remote bare metal visual examinations.

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

The inspectors verified that the basis for the reactor pressure vessel head temperatures used in the susceptibility ranking calculation was plant specific information. As of September 18, 2003, the Unit 1 RPV head had an EDY of 2.0 (normalized to 600 degrees F) which is documented in susceptibility ranking calculation NES-MS-10.02, "Exelon Standard for Determining PWR RPV Head Penetration Inspection Categories."

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

Non-visual examinations were not required to be performed during this outage.

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

Yes. The inspectors reviewed the procedures used for identification and resolution of boric acid leakage from pressure-retaining components above the RPV head.

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

Yes. The inspectors verified that visual examinations to detect potential boric acid leaks from pressure-retaining components above the RPV head were conducted. Residue from inactive leaks, originating from above the head, could be seen on the following five nozzles: #21, #66, #68, #78 and #77. The locations correspond to core exit thermocouple nozzle assemblies which had previously leaked. Replacement of the assemblies with a modified design is planned. The licensee documented the leakage residue in CR 178059; "Boron Residue Collecting on Vessel Head Penetrations." At the conclusion of the inspection, the licensee vacuum cleaned the residue and other debris from the head. There were no indications of vessel head penetration nozzle leakage.

c. <u>Findings</u>

No findings of significance were identified.

.2 Reactor Pressure Vessel Lower Head Penetration (LHP) Nozzles (NRC Bulletin 2003-02) (TI 2515/152)

a. Inspection Scope

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.

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, 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 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 using a crawler and a camera 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 color acuity and visual resolution and noted that it was consistent with the procedure requirements. The licensee demonstrated the capability of the remote camera system to resolve color and 0.158 inch high lower case character from 24 inches. Nevertheless, the resolution approached 0.044 inch lower case characters at distances under 12 inches under available lighting. The licensee used 12 inch distance as the maximum distance allowed for the examination of the nozzle interface area and similarly established a minimum distance of 3 inch for resolution of these lower case characters. The inspectors noted that the remote picture quality appeared to provide a superior inspection to that available based on a direct visual examination conducted from the access doors in the service structure. Overall, the inspectors considered that the quality of the remote visual examination was excellent based on the ability to resolve 0.044 inch lower case characters.

The licensee's response to NRC Bulletin 2003-02 under "Process to Resolve Sources of Findings," stated, "Methods available to evaluate relevant indications of leakage (i.e., boric acid residue, not staining) include sample collection for chemical and isotopic analysis." The inspectors noted that the procedure ER-AP-335-1012, Revision 0, "Visual Examination of PWR Reactor Vessel Head Penetrations," specified no requirement for such chemical and isotopic analyses. Also, Paragraph 2.1, "Material and Special Equipment," did not specify any resolution capability of the visual aids and the equipment used in performing the remote visual examination. However, there was no indication of leakage from the J-groove weld which would have required chemical analysis, and the resolution capabilities far exceeded the minimum industry standards.

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 bare metal 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."

5. 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)?

The bottom head has vertical insulation panels that cover the sides of the vessel. A flat insulation panel is mounted to the vertical insulation panels approximately 8 inches below the bottom of the vessel. Access to the bottom of the vessel is provided through periphery panels.

A remotely operated crawler with zoom camera was placed on top of the flat panel insulation. Each lower head penetration nozzle was examined for 360 degrees and the entire examination was recorded on a videotape.

The bottom head had rust-colored stains (1 to 2 mil thick) on the J-groove welds and adjacent areas from previous reactor cavity seal leakage. There was no indication of leakage from the J-groove weld which would have easily penetrated the stained surface.

6. Could small boric acid deposits, as described in the Bulletin 2003-02, be identified and characterized?

Yes. Through review of the 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 bare metal visual examination of the reactor vessel bottom head.

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

None. The bare metal remote visual inspections did not identify any material deficiencies associated with the LHP nozzles that required repair.

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

There were no impediments to the remote visual examinations. Access to the LHP nozzles was provided through the bottom head periphery insulation panels. A clearance of approximately 8 inches existed between the bottom of the vessel and the flat insulation panels.

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

Yes. There were rust-colored stains (1 to 2 mil thick) on J-groove welds and adjacent areas from previous cavity seal leakage. The inspectors verified that the sources of leakage were identified and appropriately attributed to reactor cavity seal leakage. At the conclusion of the inspection, the licensee pressure washed the bottom head and conducted another bare metal visual examination to set up a baseline for future examination.

c. Findings

No findings of significance were identified.

.3 Reactor Containment Sump Blockage (TI 2515/153)

a. Inspection Scope

The inspectors reviewed the licensee's response to NRC Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors." This bulletin addressed issues associated with potential post-accident debris blockage that may prevent operation of the containment emergency sumps during the recirculation mode. The NRC was tracking final resolution of this industry concern under Generic Safety Issue 191, "Assessment of Debris Accumulation on Pressurized Water Reactor Sump Performance."

The inspectors verified that the licensee's compensatory actions were either implemented or were scheduled to be implemented consistent with the response. This was accomplished, as applicable, by reviewing training records, procedures, CRs, and interviewing plant operators. In addition, the inspectors observed a simulator training scenario for a sump clogging. For the sump inspections, the inspectors verified that any identified deficiencies were entered into the licensee's corrective action program for resolution. Those documents specifically reviewed during this inspection are listed in the Attachment. This TI was not a part of the baseline inspection program and was therefore not considered a sample. The TI is considered complete for both units.

b. Evaluation of Inspection Requirements

In accordance with requirements of TI 2515/153, the inspectors evaluated and answered the following questions:

1. For units that entered refueling outages after August 31, 2002, and subsequently returned to power: Was a containment walkdown to quantify potential debris sources conducted by the licensee during the refueling outage?

Yes. The licensee entered the twelfth Unit 1 refueling outage on September 22, 2003, and the tenth Unit 2 refueling outage on September 16, 2002. During both refueling outages, the licensee conducted walkdowns of the emergency recirculation sumps. The inspectors accompanied the licensee during the walkdown of the Unit 1 sump. The results of the inspectors' walkdown were documented in Sections 1R20 and 1R22 of this report.

2. For units that are currently in a refueling outage, is a containment walkdown to quantify potential debris sources being conducted during the current refueling outage?

Yes. See above.

3. For units that have not entered a refueling outage between September 1, 2002, and the present, will containment walkdown to quantify potential debris sources be conducted during the upcoming refueling outage?

Not applicable.

4. Did the walkdowns conducted check for gaps in the sumps' screened flowpath and for major obstructions in containment upstream of the sumps?

Yes. During both the Unit 1 and Unit 2 refueling outages, the inspectors performed containment walkdowns to evaluate the licensee's process for maintaining containment cleanliness, in particular, for identifying and removing potential sources of debris that could clog the emergency sumps. No significant problems were identified during these walkdowns.

The licensee performed the walkdowns of the emergency sumps in accordance with station Engineering Surveillance Requirement Procedure BVSR 5.2.8-1, "Visual Surveillance of Containment Recirculation Sumps," Revision 2. This procedure required, in part, that licensee engineering staff evaluate the overall material condition of the sumps by looking for gaps or tears in the screened flowpath and for potential blockage in the internal sump piping. The inspectors reviewed the surveillance test results for the last inspection on each unit and verified that no significant gaps or tears in the screened flowpath or potential blockage of the internal sump piping were noted.

In addition, the inspectors' visual inspection of the Unit 1 sump confirmed no significant gaps or tears in the screened flowpath or potential blockage of the internal sump piping.

5. Are any advanced preparations being made at the present time to expedite the performance of sump-related modifications, in case it is found to be necessary after performing the sump evaluation?

No. The licensee did not plan to make any modifications to the sumps. The licensee concluded that existing controls in conjunction with interim compensatory measures (as described in the response) would ensure the operability of the emergency sumps.

Note: During the inspectors' review of the licensee's training for the sump clogging events, the inspectors noted that the combination of the required reading assignment and simulator training provided to the operators was appropriate to ensure proper identification and response to the event. However, during the observations of the simulator training, the inspectors noted some confusion by the operators during the implementation of the licensee's Procedure BCA 1.1, "Loss of Emergency Coolant Recirculation," Revision 103. The confusion occurred during the operators' attempt to reestablish injection to the RCS using the ECCS pumps by taking a suction from the RWST. The procedure did not specify that the operators open the injection valves. During subsequent discussions with the licensee, the inspectors determined that the problem was related to the transition points from Procedure BEP ES-1.3, "Transfer to Cold Leg Recirculation," Revision 101 to Procedure BCA 1.1. Under some scenarios, transition to BCA1.1 occurred before closing the RWST suction valves. Therefore, re-establishing suction from the RWST was achievable. However, for those cases when transition occurred after the valves were closed such as that observed in the simulator, additional direction was needed to establish ECCS injection using the RWST as the suction source. The licensee initiated CR 183943 to address this issue.

c. Findings

No findings of significance were identified.

.4 (Updated) URI 50-454/03-02-03: Evaluation for Unit 1 Potentially Exceeding Licensed Thermal Power Limits. This issue was discussed in Section 4OA3.2 of this report but remains unresolved pending the completion of the ongoing review by the NRC Office of Nuclear Reactor Regulation.

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 January 8, 2003. 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 <u>Interim Exit Meetings</u>

Interim exits were conducted for:

- Occupational Radiation Safety ALARA and access control programs inspection with Mr. S. Kuczynski on October 3, 2003.
- Inservice Inspection (IP 71111.08), Temporary Instruction TI 2515/150, Revision 2, and Temporary Instruction TI 2515/152, with Mr. S. Kuczynski on October 17, 2003.
- Heat sink biennial inspection with Mr. S. Kuczynski on December 12, 2003. The inspector reviewed and returned one proprietary document.

4OA7 <u>Licensee-Identified Violations</u>

The following violations of very low significance were identified by the licensee and are violations of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Manual NUREG-1600, for being dispositioned as NCVs.

**Cornerstone: Mitigating Systems**

1. Technical Specification 3.7.1 required that MSSVs be operable as specified in TS Table 3.7.1-2 or within 4 hours reduce power to less than or equal to that specified in TS Table 3.7.1-1. Furthermore, if this action was not completed in the specified time, the plant was required to be in Mode 3 in 6 hours. Contrary to this, as described in LER 50-454-2003-004-00, on September 16, 2003, the lift settings for MSSV 1MS016A and 1MS015D were found below the 3 percent limit allowed in TS Table 3.7.1-2. Based on engineering judgement, it is likely that the valves were outside the TS value in excess of the time allowed by the TS limiting condition for operation. This violation is of very low safety significance because the condition was bounded by the safety analysis report. The licensee entered this event into its action tracking system as CR 176050

2. 10 CFR Part 50, Appendix B, Criterion III, Design Control, states, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions.

   Contrary to the above, as of August 28, 2003, the licensee failed to assure that the design basis was correctly translated in the 120 volts alternating current degraded voltage calculation for safety-related instrumentation based on an unverified assumption concerning the operability of several instruments under degraded voltage conditions. This issue was entered into the licensee's corrective action program as CR 174155.

ATTACHMENT: SUPPLEMENTAL INFORMATION

1

# SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee

S. Kuczynski, Site Vice President
D. Hoots, Plant Manager
B. Adams, Engineering Director
B. Barton, Radiation Protection Outage Planner
D. Combs, Site Security Manager
D. Goldsmith, Radiation Protection Director
W. Grundmann, Regulatory Assurance Manager
K. Hansing, Nuclear Oversight
B. Youman, Maintenance Manager
S. Kerr, Chemistry Manager
S. Koernshild, Inservice Inspection Engineer
R. Kolo, Training Manager
S. Leach, Radiation Protection Instrument Coordinator
R. McBride, Inservice Inspection Engineer
D. Palmer, Radiation Protection - ALARA
D. Sible, Byron Engineering
J. Smith, Byron Engineering
M. Snow, Work Management Director
S. Stimac, Operations Manager
D. Thompson, Lead HP Technical
N. Vakili, Programs Engineering, Generic Letter 89-13 Program Coordinator
J. Young, Welding Administrator

Nuclear Regulatory Commission

A. Stone, Chief, Projects Branch 3, Division of Reactor Projects
N. Valos, Operations Examiner, Division of Reactor Safety
S. Ray, Senior Resident Inspector, Braidwood Station

## LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

| | | |
|---|---|---|
| 05000454/2003007-01<br>05000455/2003007-01 | NCV | Failure to Identify and Correct a Condition Adverse to Quality With Regard to Non-Conservative Error in PR11J Setpoint Analysis (Section 1R15) |
| 05000454/2003007-02<br>05000455/2003007-02 | NCV | Failure to Update the Updated Final Safety Analysis Report in a Timely Manner (Section 1R17) |

Closed

| | | |
|---|---|---|
| 50-454/455-02-02-02 | URI | Non-Conservative Error in PR11J Setpoint Analysis (Section 1R15) |
| 05000454/2003003-00<br>05000455/2003003-00 | LER | Licensed Maximum Power Level Exceeded Due to Inaccuracies in Feedwater Ultrasonic Flow Measurements Caused by Signal Noise Contamination (Section 4OA3.2) |
| 05000454/2003004-00 | LER | Two Main Steam Safety Valves Lift Setpoints Found Out of Tolerance During Testing Due to Unknown Causes (Section 4OA3.3) |

Discussed

| | | |
|---|---|---|
| 50-454/03-02-03 | URI | Evaluation for Unit 1 Potentially Exceeding Licensed Thermal Power Limits (Sections 4OA3.2, 4OA5.4) |

## LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather Protection

CR 186194; Winds at Byron in Excess of 40 mph Sustained
CR 184400; MCC Breakers Found Off After Being Verified On, November 3, 2003
CR 183702; Scheduled Work vs. Scheduled Non-Licensed Operators, October 29, 2003
CR 182207; 22B LP Htr High Level Alarm (Unexpected), October 22, 2003
CR 165758; Scheduling 0B VC Chiller Oil Skimmer Mod, July 1, 2003
WO 507372; Freezing Temperature Protection - Protected Area Buildings Ventilation System and TKS, October 13, 2003

1R04 Equipment Alignment

CR 182757; Above Ground Diesel Tank Found Unlocked, October 24, 2003
CR 154998; Potential of Adverse Impact on Configuration Control, April 21, 2003
CR 132570; OA SX PP C/O Master Card Still Hanging with Equipment RTS'd, November 21, 2003
CR 134864; 480 VAC MCC Breakers Not in Position IAW the Electrical Lineups, December 8, 2003
CR 083807; 2B DG C/O Placement Configuration Control Event - High Impact, November 25, 2003
CR 173710; Potential of Causing Both AF Pumps to be Inoperable if AF024 Isolated, August 29, 2003

CR 142546; Valve Found Out of Expected Position, 2A FW Pp Warmup, February 2, 2003
CR 177627; Loss of Running RH pp Discharge Pressure Ind., September 26, 2003
CR 177180; Operability of 1SI8801A/B Questioned During Surveillance, September 24, 2003
Focus Area Self-Assessment; Configuration Control, June 1, 2002 through June 1, 2003
CR 184085; Adverse Trend in Configuration Control Errors, October 31, 2003

1R05 Fire Protection

CR 185754; Impaired Access to Safety Related Equipment, November 10, 2003

1R07 Heat Sink Performance

Condition Report 080479; Foreign Material Exclusion Concerns in Essential Service Water System; dated October 26, 2001
Condition Report 084018; Significant Material Loss Due to Corrosion on the Gasket Seating Surfaces of 2B Diesel Generator Jacket Water Heat Exchangers; dated November 26, 2001
Condition Report 084260; Ceramalloy Failure on 2B Diesel Generator Jacket Water Heat Exchangers; dated November 28, 2001
Condition Report 092605; 2A Diesel Generator Jacket Water Heat Exchangers Corrosion/ Pitting; dated January 28, 2002
Condition Report 099749; Essential Service Water Inlet and Outlet Pipes for 1B Auxiliary Feedwater Pump Lube Oil Cooler Contain Internal Buildup from Silt and Corrosion Products; dated March 18, 2002
Condition Report 123498; 2B Auxiliary Feedwater Diesel Room Cooler Discovered with Corroded Outer Divider Plates; dated September 19, 2002
Condition Report 124919; Generic Letter 89-13 Inspection Checklist Does Not Have a Statement of Acceptance Criteria; dated September 27, 2002
Condition Report 135353; Blooming of Zinc Anodes in 1B Charging Pump Oil Coolers; dated December 12, 2002
Condition Report 137005; 2B Essential Service Water Pump Lube Oil Cooler Failed Tube Blockage Acceptance Criteria; dated December 20, 2002
Condition Report 139746; 1B Essential Service Water Pump Lube Oil Cooler Failed Tube Blockage Acceptance Criteria; dated January 16, 2003
Condition Report 141451; 2A Essential Service Water Pump Lube Oil Cooler Failed Tube Blockage Acceptance Criteria; dated January 28, 2003
Condition Report 142823; Ceramalloy Failure on 0B Essential Service Water Makeup Pump Jacket Water Heat Exchanger; dated February 4, 2003
Condition Report 145070; 1A Diesel Generator Jacket Water Heat Exchanger Corrosion/ Pitting; dated February 18, 2003
Condition Report 149227; Low Essential Service Water Flow to Unit 1 Component Cooling Heat Exchangers Through Valve 1SX-007; dated March 15, 2003
Condition Report 152784; Corrosion Discovered on Piping Attached to 1B Residual Heat Removal Pump Room Cooler; dated April 7, 2003
Condition Report 154572; Essential Service Water Piping Non-Destructive Examination Failed the Minimum Wall Thickness Exam; dated April 18, 2003

Condition Report 157568; 1B Diesel Generator Jacket Water Heat Exchangers Corrosion/ Pitting and Failed Ceramalloy Coating; dated May 7, 2003
Condition Report 169329; Corroded Supply and Return Flanges on 1A Safety Injection Pump Oil Cooler; dated July 28, 2003
Condition Report 169367; 1A Essential Service Water Pump Bearing Oil Cooler Failed Tube Blockage Acceptance Criteria; dated July 29, 2003
Condition Report 177861; Belzona Pieces Found in Blocked Tube in Unit 1 Auxiliary Feedwater Pump Room Cooler; dated September 27, 2003
Condition Report 182809; Tube Plugging Acceptance Criteria Exceed for Control Room A Chiller; dated October 24, 2003
Condition Report 183397; Ceramalloy Failure on Unit 0 Control Room Chiller; dated October 28, 2003
Condition Report 186847; Excessive Amount of Silt Buildup Identified Inside Feedwater Oil Coolers; dated November 17, 2003
Condition Report 190896; Recommendations from 2003 NRC Biennial UHS Inspection; dated December 15, 2003 (issued as a result of the inspection)
Data Sheets; Eddy Current Examination - Unit 2 Component Cooling Water Heat Exchanger; dated January 12, 2000
Data Sheets; Eddy Current Examination - Unit 2 Component Cooling Water Heat Exchanger; dated February 1, 1999
Data Sheet; Component Cooling Water Heat Exchanger
Data Sheet; Residual Heat Removal Heat Exchanger; Revision 2
Internal Memorandum; Eddy Current Examination of Unit 2 Component Cooling Heat Exchanger; dated January 28, 1999
Internal Memorandum; Eddy Current Examination of Unit 1 Component Cooling Heat Exchanger; dated March 10, 1999
Internal Memorandum M-06165-98; Eddy Current Examination of Unit 0 Component Cooling Heat Exchanger; dated July 22, 1998
Letter DG00-000053; Byron Unit 2 Component Cooling Heat Exchanger Eddy Current Evaluation; dated January 18, 2000
Sargent and Lundy Calculation 067961; Database for Minimum Wall Thickness and Branch Reinforcement Requirements; dated April 8, 1994
Surveillance BVP 8000-30, Attachment D; Generic Letter 89-13 Heat Exchanger Inspection Cover Sheet for Unit 0 Component Cooling Heat Exchanger; completed October 19, 1990, January 27, 1992, September 20, 1993, and August 17, 1998
Surveillance BVP 8000-30, Attachment D; Generic Letter 89-13 Heat Exchanger Inspection Cover Sheet for Unit 1 Component Cooling Heat Exchanger; completed May 3, 1991, April 15, 1995, February 19, 1993, and March 24, 1999
Surveillance BVP 8000-30, Attachment D; Generic Letter 89-13 Heat Exchanger Inspection Cover Sheet for Unit 2 Component Cooling Heat Exchanger; completed October 19, 1990, October 1, 1993, February 3, 1992, July 27, 1999, and January 28, 2000
Synopsis of Flow Accelerated Corrosion Minimum Wall Thickness Results from Surveillance, 2BVSR XII-12; provided December 12, 2003
Synopsis of Heat Exchangers within the Generic Letter 89-13 Program Showing Coatings and Water Flow; provided December 12, 2003
Westinghouse Calculation CN-FSE-00-4; Cooldown for Uprating; Revision 1

1R08 Inservice Inspection

PDI-UT-2; WesDyne Procedure on Ultrasonic Examination of Austenitic Piping Welds; Revision 3
PDI-UT-1; WesDyne Procedure on Ultrasonic Examination of Ferritic Piping Welds; Revision 3
Work Order Package 99218401-10; Radiographic and Magnetic Particle Examination Records for Field Welds 1, 2, and 3
Work Order Package 00469595-08; Magnetic Particle Examination of Upper Stationary Channel Head and VT-2 Visual Examination Record
Ultrasonic Examination Records for Weld No. 1RC21AB-8"-J07
Ultrasonic Examination Records for Weld No. 1RC21AB-8"-J08
Ultrasonic Examination Records for Weld No. 1RC21AB-8"-J10
Byron Inspection Data Report on Flow-Accelerated Corrosion Subcomponent: 1FW001B-DS Pipe Red Grid
Byron Inspection Data Report on Flow-Accelerated Corrosion Subcomponent: 1FW001C-DS Pipe Red Grid
Work Order Package 99218401-10; Replacement of Valves 1MS 020A, 1MS 021A, and Pipe 1MS 20AA in the Main Steam Tunnel
Work Order Package 00599592-01; Replacement of Valve 1CV 8384B in 1B Seal Injection Filter Inlet Isolation Line
Work Order Package 00469595-08; Repair of Upper Stationary Channel Head in 1B DG Jacket Water Upper Cooler
CR No. 154572; 0SX161B Pipe NDE Failed the Minimum Wall Thickness Examination
CR No. 156160; Possible Carbon Steel Weld on Stainless Steel
CR No. 128711; Final Weld Inspection. Welder Used ER 308 and E308 in Lieu of ER 309 and E 309
Risk-Informed Inservice Inspection Plan for the R-12 Outage

1R12 Maintenance Effectiveness

Condition Reports on Rod Drive System, November 19, 2001-November 19, 2003
CR 92680; Control Rods Stepped in 2.5 Steps With No Apparent Cause, January 28, 2003
CR 103876; Evaluation of SXCT of Fan Motor Noise and Vibration Data, April 15, 2002
CR 106419; CRs Not Written Against Issues on Outage OCC Issues Board, April 26, 2002
CR 106499; SXCT 0D Fan Assembly - Elevated Vibration on Midshaft Bearing, May 02, 2002
CR 124948; Lubrication Program Failure, September 25, 2003
CR 126665; Loss of Control Power for 0G SXCT Fan, October 09, 2002
CR 128209; Unplanned Entry into 2BOA ROD-1 for Auto Rod Motion, October 20, 2002
CR 128651; Improvement Opportunity for Rod Control System, October 20, 2002
CR 131345; Deficiency Identified for 0G SX Fan During Board Walkdown, November 13, 2002
CR 131571; 0A SX Fan Oil Low Level Not Meeting Operations Department Standards, November 14, 2002
CR 132060; MCR Habitability/UFSAR Concern/Multiple Site Negative Trend, November 18, 2002

CR 138023; SXCT Fan Blade Repair Inadequate Evaluations, December 06, 2003
CR 138130; MCR Low Humidity, January 4, 2003
CR 140314; Rod Drive Urgent Alarm Lessons Learned, January 19, 2003
CR 140143; Rod Control Urgent Failure Alarm - Rods Would Not Move, January 19, 2003
CR 143392; Control Rods Fail to Move, February 7, 2003
CR 144946; 0B SX Fan Oil Pressure Low, February 18, 2003
CR 146983; UFSAR Compliance/MCR Distractions, March 1, 2003
CR 115887; 1B Rod Drive M/G Set Making Abnormal Noise, July 17, 2002
CR 177882; Excessive Grease in 1B RD MG Generator Outboard Bearing, September 27, 2003
CR 177978; 0B VC Chiller Failed to Start During 1BOSR 8.1.9-2, September 28, 2003
CR 177998; Reactor Trip Breaker (RTA) Failed Surveillance Testing, September 26, 2003
CR 183007; Oil Sample Line Support, October 25, 2003
CR 183367; 0A & 0B Control Room Chiller Work Window Issues, October 28, 2003
CR 184068; Chillers Outboard Motor Bearing Bad, October 29, 2003
CR 184142; Failure to Adequately Plan Contingency for 0A VC Chiller, October 29, 2003
CR 184277; Poor Performance of Machining Repairs on condenser Flanges, November 1, 2003
CR 184944; Improper Installation of EC 340158 (SXCT Oil Sample Line)
CR 184961; Unexpected Condition/Delays of reassembly of 0A VC Chiller, November 4, 2003
CR 184962; 0A VC Chiller Failed Functional PMT Run after Maintenance, November 5, 2003
CR 185084; 0A VC Chiller Tripped on Low Evaporator Temperature, November 5, 2003
CR 185162; Installation of SXCT Gearbox Oil Sample Line, November 06, 2003
CR 185259; Chronic Low Humidity, November 6, 2003
CR 186187; 0A MCR Chiller Oil Level Dropping Following Work Window, November 12, 2003
CR 186954; Recurring VC Humidity Issue Re-Scheduled to Spring, November 17, 2003
CR 189828; 0A VC Chiller Surging, December 09, 2003
AR 132060-01; ACE to Evaluate the Long Term Equipment Performance Issues Associated with Steam Humidifiers, January 30, 2003
AR 132060-14; Vendor Evaluation Followup on Vendor Evaluation of the Humidification System and Create New Action Items if There are Inadequacies to Address, April 29, 2003
CR 087964; MCR Habitability/Safety Category I Component Service Life Issues, December 23, 2001
RD System Requests Since November 1, 2001; Sorted by Year Created, Enter Date, Status, ETN
Rod Drive Maintenance Rule Data
Maintenance Rule-Performance Criteria VC1; Provide Ventilation for Main Control Room Envelope; including Normal, Abnormal, and Emergency Functions
Maintenance Rule-Evaluation History WO1; Provide Chilled Water (WO) to Support the Main Control Room (MCR Ventilation (VC) System, October 16, 2003
Maintenance Rule-Performance Criteria WO1
CR 183007; Apparent Cause Evaluation; SX Cooling Tower Oil Sample Line Modification, October 24, 2003

Maintenance Rule - Performance Monitoring (Reliability Graph); November 2001 through November 2003
Maintenance Rule - Performance Criteria; Ultimate Heat Sink Temperature Control
Maintenance Rule (a)(1) Disposition Checklist and Documentation Summary for Ultimate Heat Sink Temperature Control

1R13 Maintenance Risk Assessments And Emergent Work Control

Prompt Investigation Report; 2B Auxiliary Feedwater Pump Outboard Bearing Oil Leak
Byron's Archival Operations Logs, December 1, 2003 to December 3, 2003
CR 188844; Differences in AF Lube Oil Pressures Identified, December 2, 2003
CR 188670; 1B AF Pump Outboard Bearing Does Not Have a Breather Cap, December 1, 2003
CR 188686; Grinding Defects Found on 2AF01PB O/B Bearing Housing Cover, December 2, 2003
CR 188595; 2B AF Pp Shaft Driven Oil Pump Seal Leak, December 1, 2003

1R15 Operability Evaluations

CR 00174155; Device Minimum Operating Voltage Not Reflected in Passport, September 03, 2003
CR 00173650(Braidwood); Device Minimum Operating Voltage Not Reflected in Passport, August 28, 2003
CR 183734; 05 GPM Seal Leak on 1A CV Pump, October 29, 2003
WO 00614589(Braidwood); Bench Test Spare Validyne P361 and P532D Transmitters, September 23, 2003
NSP OP-AA-108-108, Attachment 1, Item #8; Byron Station Unit 1 - Open Operability Evaluation Status, October 06, 2003
CR 176387; Insulation Left Removed from 2RC01BD Flange MJ-212A, September 18, 2003
CR 179287; 1A SX Pump Damaged Unistrut Support on Casing Vent Line, October 1, 2003
CR 179352; Motor Degradation, October 4, 2003
CR 178414; New Packing Installed in FRVs Has Higher Friction Than Expected, September 29, 2003
CR 184344; Unit 1 Letdown Hx Swap Issues, November 2, 2003
CR 184896; PI&R-2A DG Lube Oil Cooler HX Flange Stud Bolt Tightness, November 4, 2003
CR 184192; RX Head Vent Operability Evaluation Deficiencies, October 31, 2003
CR 183661; NOS Identified LCOAR Logging Issues, October 27, 2003
CR 177238; Oil Sample Indicates Adverse Condition on 2CC01PA, September 24, 2003
WO 519659; Install SX Cooling Tower Fan Gearbox Oil Sampling 0SX03, October 24, 2003
Engineering Change #340158 006; SX Cooling Tower Fan Gearbox Oil Sampling, December 11, 2002
CR 183007; Oil Sample Line Support, October 25, 2003
CR 184944; Improper Installation of EC 340158 (SXCT Oil Sample Line), November 5, 2003

WO 121833; Valve is Frozen in Position Will Not GO Open or Closed, November 25, 2003
WO 121832; Flow Indicating Lower Than Expected, November 25, 2003

1R16 Operator Workarounds

Operations - Aggregate Assessment of Equipment Performance
Operator Challenges; Byron Nuclear Generating Station POD, Day of the Week Agenda, December 29, 2003

1R19 Post Maintenance Testing

WO 634796; ASME Surveillance Requirements for Centrifugal Charging Pump, November 19, 2003
WO 99118092; Overhaul Pump, October 04, 2003
1BVSR 5.5.8.SX.1-1; Revision 3, August 21, 2003
WO 602939 01; SEP Perform 1BVSR 5.2.4-5; 1A CV Pump ASME Run, October 30, 2003
WO 421712 03; SEP Visual (NON-ISI), October 29, 2003
WO 421712; 1A CV Pump Outboard Seal Leak at 23-25 GPH, Replace Seal, October 29, 2003
WO 538312 01; MM - Valve Leaks By Preventing ISO to the 1A CV Pump Coolers, October 29, 2003
WO 560662 01; Small Amount of Boric Acid at Body/Bonnet on Kerotest Check, October 28, 2003
WO 560662 02; SEP VT-2 on 1CV8480A Check Valve, October 29, 2003
WO 560662 03; SEP Flow Test Check Valve, October 29, 2003
WO 421712 04; SEP 1A CV ASME, October 29, 2003
WO 00610110; ASME Test of the 1A SX PP, Discharge Check Valve and Misc System, October 04, 2003
WO 99164223; Valve is Very Difficult To Turn; October 29, 2003
WO 99118092 09; SEP PMT - ASME Surveillance, October 04, 2003
WO 99118092 16; OP PMT, Verify Flood Seal 1DSFS083 Reinstalled, October 04, 2003
WO 99118092 08; OP PMT Leaks and Bearing Temps, October 04, 2003
WO 99118092 26; OPS PMT - Visual, October 04, 2003
WO 99164223 04; SEP PMT - Visual (NON-ISI), October 29, 2003
WO 00426437 01; 1A Diesel Generation SAFE S/D Sequence and Single Load Reject, October 5, 2003
1BOSR 8.1.9-1; 1A Diesel Generator Safe Shutdown Sequencer and Single Load Rejection Test - 18 Month
1BVSR 5.5.8.SX.1-1; Unit One Test of the 1A Essential Service Water Pump and Discharge Check Valves, October 04, 2003
PQD Report; Job Assignment-Group NSSS, October 22, 2003
1BVSR 5.2.4-5; ASME Surveillance Requirements For 1A Centrifugal Charging Pump and Check Valve 1CV8480A Stoke Test, October 29, 2003
CR 183014; 1A CV Pump Breaker Bus Connecter Misaligned, October 29, 2003
CR 183714; 1CV01PA 4KV Breaker Misalignment Issues, October 29, 2003
CR 186895; 1A CV Pump Inoperable, Unavailable, Unplanned LCOAR, November 17, 2003

CR 180528; Availability/Operability of 1RY455A Pending PMT, October 12, 2003
CR 180512; 1RY455A Stroke Time Test Failure, October 12, 2003
1BOSR 0.5-2.RY.2; Unit One 1RY455A and 1RY456 Stroke and Position Indication Test, Revision 7

1R20 Refueling and Outage Activities

CR 186118; Better Awareness of Finding Boric Acid Leaks, November 12, 2003 (NRC Identified)
1BGP 100-1T2; Mode 5 to 4 Checklist, Revision 14
Byron Pre-PORC Management Challenge Meeting for Mode 4 Startup Monday, October 6, 2003
WO 113386; B1R12 Condition - Remove Duct Tape from Copper 1A Line, September 25, 2003
WO 618334; Failing Low SG Loop 1D STM Press, September 24, 2003
WO 113707; Valve Plug Has Indications in the Seating Area, September 27, 2003
B1R12 Issues; Open Items
B1R12 Vulnerabilities List
EC 362025; A Piece of Fiberboard Was Found During an NRC Walkdown Placed Under an Oil Pan Installed on the C RCP
WR 113802; Packing Leak, Packing Has Dried Boron On It, September 29, 2003
WO 609180 01; B1R12 Contingency to Repair if Valve Disc Gets Stuck in the Seat, October 2, 2003
WO 619278 01; EM Troubleshoot Valve Showing Dual When Opened, October 2, 2003
WO 623115; Insulation Buckles Not Closed on 1C Steam Generator, October 9, 2003
CR 184714; Unit 1 Containment Mode 4 Walkdown with NRC, October 11, 2003 (NRC Identified)
CR 183320; NSP OU-AP-104 Conflict with BOP CC-10, October 27, 2003 (NRC Identified)

1R22 Surveillance Testing

1BVSR 5.2.8-1; Visual Inspection of the ECCS Recirculation Sumps, Revision 2, October 7, 2003
CR 179809; Unit 1 ECCS Sump Inspection Findings, October 7, 2003
WO 426440 01; Visual Inspection of the Containment Recirculation Sumps, October 7, 2003
CR 186578; Missed IST Valve Strokes for 1CC9458 and 1CC9467A, November 18, 2003
1BVSR 6.1.1-24; Unit 1 Summation of Primary Containment Type “B” & “C” Local Leakage Tests for Acceptance Criteria

1R23 Temporary Plant Modifications

Plant Issue Resolution Summary; CV/1CV065A, October 30, 2003
CR 182797; 1CV065A Pipecap Leak Furminite Re-injection Repair Failure, October 29, 2003

1EP6 Drill Evaluation

Utility Message No. 1, 2, 3, and 4; Nuclear Accident Reporting System (NARS), October 22, 2003
Byron 2003 Pre-Exercise Findings and Observation Report, October 28, 2003

2OS1 Access Control to Radiologically Significant Areas

AR No. 173884; Lost ED; dated August 27, 2003
AR No. 176207; Locked High Rad Door Alarms Inoperable; dated September 17, 2003
AR No. 177325; Poor Rad Worker Practice; dated September 24, 2003
AR No. 177794; Individuals Identified with Internal Contamination; dated September 26, 2003
AR No. 177892; Individual Discovered Sleeping in Unit 1 Containment; dated September 27, 2003
AR No. 177896; FME Bags Labeled "RPA Use Only" Found in Main Steam Tunnel; dated September 27, 2003
AR No. 178485; Individual Unaware of Dress Requirements Following ALARA Brief; dated September 30, 2003
AR No. 178820; Poor Rad Practices in U-1 Containment; dated October 1, 2003 (NRC-Identified)
AR No. 179050; Locked High Radiation Area Controls; dated October 1, 2003
MA-AA-716-015; Control of Diving; Revision 2
RP-AA-441; Evaluation and Selection Process for Radiological Respirator Use; Revision 2
RP-AA-460; Controls for High and Very High Radiation Areas; Revision 2
RP-AA-461; Radiological Controls for Contaminated Water Diving Operations; Revision 0
RP-BY-500-1003; Radiological Controls for Handling Items and Hanging Activated Parts in the Spent Fuel Pool; Revision 0
RWP No. 10002419; Miscellaneous AOV Work: Including Operator and Process Diaphragm Work; Revision 01
RWP No. 10002424; Remove and Reinstall Reactor Head and Upper Internals; Revision 01
RWP No. 10002427; Reactor Coolant Pumps: Inspection/Maintenance/Repair (All Loops); Revision 00
RWP No. 10002443; Reactor Cavity Decon: All Activities; Revision 00
RWP Plan No. 10002448; Scaffold: Staging, Building, and Removal (Auxiliary Building and Containment); Revision 02
RWP/ALARA Plan No. 10003532; Contaminated Water Diving Operations; Revision 00
Survey No. 03-1220; Post-Dive Suit Survey; dated August 28, 2003
Survey No. 03-1899; Fuel Transfer Canal (Unit 1 Side) Survey; dated September 29, 2003

2OS2 ALARA Planning And Controls

AR No. 174266; Dose Estimate Exceeded; dated September 3, 2003
AR No. 176031; RP Outage Readiness/ALARA FASA; dated September 5, 2003
AR No. 177163; Forced Oxidation Peak Higher Than Projected; dated September 23, 2003

B1R12 ALARA Index; dated September 16, 2003
Byron Station Nuclear Oversight B1R12 Rapid Trending Report - Radiation Work Practices; dated September 28, 2003
Focus Area Topic: Radiation Protection B1R12 Outage Readiness and Preparation; dated September 4 - 5, 2003
RWP/ALARA Plan No. 10002419; Miscellaneous AOV Work: Including Operator and Process Diaphragm Work; Revision 01
RWP/ALARA Plan No. 10002421; Reactor Head Component Disassembly and Reassembly Including Lift Prep; Revision 01
RWP/ALARA Plan No. 10002427; Reactor Coolant Pumps: Inspection/Maintenance/Repair (All Loops); Revision 00
RWP/ALARA Plan No. 10002443; Reactor Cavity Decon: All Activities; Revision 00
RWP/ALARA Plan No. 10002448; Scaffold: Staging, Building, and Removal (Auxiliary Building and Containment); Revision 02
RP-AA-401, Attachment 7; Work-In-Progress Review: RWP No. 10002431; dated September 28, 2003
RP-AA-401, Attachment 7; Work-In-Progress Review: RWP No. 10002448; dated September 27, 2003
RP-AA-401, Attachment 7; Work-In-Progress Review: RWP No. 10002460; dated September 28, 2003

4OA1 Performance Indicator Verification

Byron's Archival Operations Narrative Logs, July 1, 2002 - June 30, 2003
LS-AA-2060; Monthly Data Elements for NRC Safety System Unavailability-Reactor Core Isolation Cooling (BWRs) or Auxiliary Feedwater (PWRs) Systems, Revision 4
LS-AA-2040; Monthly Performance Indicator (PI) Data Elements for Safety System Unavailability-Emergency AC Power, Revision 2 & Revision 3
LS-AA-2060; Revision 2, July, August 2002
LS-AA-2060; Revision 3, September 2002 through December 2002
LS-AA-2060; Revision 3, January 2003 through June 2003

4OA2 Identification and Resolution of Problems

Exelon Nuclear Organization; Positions Required for Training in Accordance with the Confirmatory Order
RS-03-085; Report of Results Related to Confirmatory Order; April 28, 2003
CR 141507; Confirmatory Order for Violation of 10 CFR 50.7; January 28, 2003
RS-03-052; Description of Results of Work Environment Review; April 11, 2003
EA-02-124; Confirmatory Order (Effective Immediately) (Office of Investigations Report No. 3-2001-005); October 3, 2002
Course Attendance Sheet; Confirmatory Order Training; February 12, 2002
Course Attendance Sheet; Confirmatory Order Training; March 6, 2003
Course Attendance Sheet; Confirmatory Order Training; March 12, 2003
Course Attendance Sheet; Confirmatory Order Training; March 13, 2003
Course Attendance Sheet; Confirmatory Order Training; March 17, 2003
Employee Protection Recent Lessons Learned; Presentation for Exelon Nuclear Managers; January-February 2003
The Importance of Creating and Sustaining a Safety Conscious Work Culture

4OA3 Event Follow-up

Reactivity Maneuver Form; November 3, 2003
Trend Graphs for Unit 1 RCS; Iodines and Xenon, October 17 through November 7, 2003
Adverse Condition Monitoring and Contingency Plan; RCS Activity Monitoring Due to Failed Fuel, Revision 2
NF-AA-430; Failed Fuel Action Plan, Revision 1
Byron's Operations Narrative Logs, October 16 through October 20, 2003
1BOA PRI-4; Abnormal Primary Chemistry-Unit 1, Revision 101
CR 181418; Entered 1BOA PRI-4 Due to 1PR06J Alert Alarm, October 17, 2003
CY-AP-120-100; Reactor Coolant System Chemistry, Revision 1
Plant Issue Resolution Summary; Unit 1 Fuel Failure - Impact on Ramping Unit to 100% from ~96.5 percent, October 18, 2003
CR 179318; B1R12 Decision Making - MSSV Root Cause Classification, September 24, 2003
CR 176050; B1R12P MSSV As Found Settings Found Outside Acceptable Range, September 16, 2003

4OA5 Other

CR 187587; Questions regarding ECCS Recirculation Sump Design; November 20, 2003
ECCS TI; Review NRC Bulletin 2003-01 Response,
Required Reading NRC 2003-01 Sump Clogging
Licensee Responses to Required Reading
EC 337314 000; Evaluate Addition of Metal boxes to Unit 2 Containment for Storage of Lead Blankets, Revision 0
EC 336048 001; Evaluate Addition of Metal Boxes to Unit 1 Containment for Storage of Lead Blankets, Revision 1
CR 183943; ECCS Sump Blocked Simulator Scenario Response, October 30, 2003
CR 180362; Insufficient corrective Actions for Coatings CR 175317, October 10, 2003 (NRC Identified)
CR 177500; Existing Containment Coatings Found Unsatisfactory, September 24, 2003
CR 178648; Unqualified Containment Coatings Previously Considered Qualified, October 1,2003
CR 175317; Level 1 Coating Applied Incorrectly on Storage Boxes in Containment, September 11, 2003
CR 177579; Tie Wraps Present FME Challenge in Containment, September 25, 2003
1BOSR Z.5.B.1-1; Containment Loose Debris Inspection, October 11, 2003
CR 179809; Unit 1 ECCS Sump Inspection Findings, October 7, 2003
2BOSR Z.5.B.1-1; Unit 2 Containment Loose Debris Inspection, Revision 3
1BOSR Z.5.B.1-1; Unit 1 Containment Loose Debris Inspection, Revision 3
BAP 1450-T2; Containment Entry Checklist, Revision 29
BAP 1450-1; Access to Containment, Revision 31
ER-AP-335-1012; Visual Examination of PWR Reactor Vessel Head Penetrations; Revision 0
Exelon Procedure; Sampling and Analysis Guidance for Deposits Found on Reactor Pressure Vessels at Various Locations; Revision 0
Westinghouse Drawing; Coordinates and Elevations of Closure Head Penetrations
Exelon Sketch of Bottom Head Instrumentation Tubes

Transco Drawing on Reactor Vessel Top Dome Insulation Layout Plan, Sections and Details
Order EA-03-009; Issuance Of Order Establishing Interim Inspection Requirements For Pressure Vessel Heads At Pressurized Water Reactors; dated February 11, 2003
NRC Letter; Byron Station, Unit 1- Notification of NRC Inservice Baseline Inspection and Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles Inspection (NRC Order EA-03-009); dated August 20, 2003
EPRI TR-112657; Electric Power Research Institute (EPRI) Topical Report (TR); Revised Risk-Informed Inservice Inspection Evaluation Procedure; Revision B
Exelon Letter to NRC on 30-Day Response to NRC Bulletin 2003-02; Leakage from Reactor Pressure Vessel Lower Head Penetration and Reactor Coolant Pressure Boundary Integrity; dated September 22, 2003
WO 99280383; Visual Inspection of the Containment Recirculation Sumps, September 27, 2002
WO 00426440; Visual Inspection of the Containment Recirculation Sumps, October 8, 2003
1BVSR 5.2.8-1; Visual Inspection of the ECCS Recirculation Sumps, Revision 1
2BVSR 5.2.8-1; Visual Inspection of the ECCS Recirculation Sumps Revision 2

## 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 |
| B1R12 | Byron Station Unit 1 Refueling Outage Twelve |
| CFR | Code of Federal Regulations |
| Ci/gm | curies per gram |
| CR | Condition Report |
| DC | Direct Current |
| DRP | Division of Reactor Projects; Region RIII |
| ECCS | Emergency Core Cooling System |
| EDY | Effective Degradation Years |
| EPRI | Electric Power Research Institute |
| gpm | gallons per minute |
| IMC | Inspection Manual Chapter |
| LER | Licensee Event Report |
| LHP | Lower Head Penetration |
| MSSV | Main Steam Safety Valve |
| NCV | Non-Cited Violation |
| NRC | United States Nuclear Regulatory Commission |
| NSP | Nuclear Station Procedure |
| PARS | Publicly Available Records |
| PI | Performance Indicators |
| PWR | Pressurized Water Reactor |
| PWSCC | Primary Water Stress Corrosion Cracking |
| RCS | Reactor Coolant System |
| RPV | Reactor Pressure Vessel |

| | |
|---|---|
| RWP | Radiation Work Permit |
| RWST | Reactor Water Storage Tank |
| SDP | Significance Determination Process |
| SSC | Structures, Systems or Components |
| TI | Temporary Instruction |
| TRM | Technical Requirements Manual |
| TS | Technical Specification |
| UFMS | Ultrasonic Flow Measurement System |
| UFSAR | Updated Final Safety Analysis Report |
| VHP | Vessel Head Penetration |