February 21, 2006

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

SUBJECT: ERRATA TO BYRON STATION, UNITS 1 & 2, NRC INTEGRATED INSPECTION REPORT 05000454/2005011; 05000455/2005011

Dear Mr. Crane:

On February 3, 2006, the U.S. Nuclear Regulatory Commission (NRC) issued Integrated Inspection Report 05000454/2005011; 05000455/2005011 (ML060390424). There was one typographical error in numbering an inspection finding on page 27. The corrected inspection finding is NCV 05000454/2005011-03; 05000455/2005011-03.

We apologize for any inconvenience to you and your staff.

Sincerely,

/RA/

Richard A. Skokowski, Chief
Projects Branch 3
Division of Reactor Projects

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

See Attached Distribution

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Plant Manager - Byron Station
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President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BYRON STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000454/2005011; 05000455/2005011

Dear Mr. Crane:

On December 31, 2005, 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 6, 2006, with Mr. S. Kuczynski and other members of your staff.

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

Based on the results of this inspection, one NRC-identified and one self-revealed findings of very low safety significance (Green) are documented in this report. One of these finding was determined to involve a violation of NRC requirements. In addition, a third 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 safety significance or Severity Level IV violation and because the issues were entered into your corrective action program, the NRC is treating these findings as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the Resident Inspector office at the Byron facility.

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

Sincerely,

/RA/

Richard A.Skokowski, Chief
Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000454/2005011; 05000455/2005011
w/Attachment: Supplemental Information

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

REGION III

Docket Nos:	50-454; 50-455
License Nos:	NPF-37; NPF-66
Report Nos:	05000454/2005011; 05000455/2005011
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	4450 N. German Church Road Byron, IL 61010
Dates:	October 01, 2005, through December 31, 2005
Inspectors:	D. Schroeder, Acting Senior Resident Inspector R. Orlikowski, Acting Senior Resident Inspector J. Taylor, Acting Senior Resident Inspector B. Bartlett, Acting Senior Resident Inspector R. Ng, Resident Inspector C. Acosta Acevedo, Reactor Engineer M. Wilk, Reactor Engineer, Region III M. Holmberg, Reactor Inspector, Region III J. House, Radiation Specialist J. Jandovitz, Reactor Inspector, Region III R. Jickling, Emergency Preparedness Analyst J. Robbins, Reactor Engineer, RIII M. Jordan, Consultant C. Thompson, Resident Inspector, Illinois Emergency Management Agency
Approved by:	R. Skokowski, Chief Branch 3 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000454/2005011; 05000455/2005011; on 10/01/2005-12/31/2005; Byron Station, Units 1 and 2; Inservice Inspection Activities, Permanent Plant Modification, Emergency Action Level and Emergency Plan Changes.

This report covers a 3 month period of baseline resident inspection and announced baseline inspections on radiation protection, heat sink performance, EP inspection and inservice inspection. The inspections were conducted by resident and inspectors based in the NRC Region III office. One Severity Level IV Non-Cited Violation and two Green findings, one of 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: Initiating Events

- Green. A finding having very low safety significance (Green) was self-revealed when the newly installed Digital Electrohydraulic System (DEH) failed to respond to operator input to initiate a turbine runback that subsequently resulted in a reactor trip. The inspectors determined that the algorithm required for turbine runback was deleted from the software database due to a compiler fault. Modification review and testing performed by the licensee failed to discover the software error. To correct the problem the licensee reinstalled the deleted software algorithm into the DEH system.

  The finding was more than minor because it affected the design control attribute of the Initiating Events cornerstone objective. The attribute objective limits the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations. Specifically, the lack of turbine runback capability contributed to a reactor trip from a feedwater system transient. The finding was determined to be of very low safety significance (Green), since it only contributed to the likelihood of a reactor trip. No violation of NRC requirements occurred. (Section 1R17)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding involving a Non-Cited Violation (NCV) of 10 CFR Part 50.55a(g)(4)ii having very low safety significance for failure to perform a VT-2 examination at nominal operating pressure for six new residual heat removal system welds that were returned to service. This finding was entered into the licensee's corrective action program.

  This finding was of more than minor significance because the licensee returned these six welds to service without completing the required pressure test and VT-2 examination, which placed this system at increased risk for undetected leakage and component failure. Operation of this system with improperly tested piping affected the mitigating systems cornerstone objective of equipment reliability. This finding was of very low safety significance because the required test and VT-2 examination were subsequently completed and all welds passed. The finding was not suitable for a significance determination process evaluation. This finding has been reviewed by NRC Management and has been determined to be a Green finding of very low safety significance. (Section 1R08)

Cornerstone: Emergency Preparedness

- Severity Level IV. The inspectors identified that the licensee had changed its standard emergency action level (EAL) scheme by revising one EAL's criteria for an Unusual Event declaration that addressed an unplanned radiological release in excess of effluent radiation monitor readings unless the release could be determined to be below Offsite Dose Calculation Manual limits within 15 minutes for releases that could not be terminated in 60 minutes or less. The inspectors determined that this EAL change decreased the effectiveness of the emergency plan, and that the licensee did not obtain prior NRC approval for this change, contrary to the requirements of 10 CFR 50.54(q). The licensee is evaluating the options to correct the EAL.

  This finding was more than minor because extending the time period required for the appropriate emergency classification of a radiological release could adversely affect the performance of both onsite and offsite emergency actions. Because the issue affected the NRC's ability to perform its regulatory function, it was evaluated with the traditional enforcement process as specified in Section IV.A.3 of the Enforcement Policy. According to Supplement VIII of the Enforcement Policy, this finding was determined to be a Severity Level IV because it involved a failure to meet a requirement not directly related to assessment and notification. Further, this problem was isolated to one EAL and was not indicative of a functional problem with the EAL scheme. Additionally, because the violation was a Severity Level IV and the licensee entered this issue into its corrective action program this finding is being treated as a Severity Level IV Non-Cited Violation of 10 CFR 50.54(q). (Section 1EP4)

B. Licensee Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power for the quarter except for the followings:

- On December 8, 2005, Unit 1 ramped down to 98 percent to swap feedwater pumps.
- On December 18, 2005, Unit 1 downpowered to 85 percent to perform a turbine valve/governor valve surveillance.

Unit 2 started the quarter shutdown for a refueling outage. On October 18, 2005, Unit 2 returned to full power operation. The unit operated at or near full power for the quarter except for the followings:

- On October 19, 2005, Unit 2 tripped due to the loss of a condensate/condensate booster pump resulting from a faulty motor. The unit subsequently returned to full power on October 22, 2005.
- On November 5, 2005, Unit 2 ramped down to 96 percent to swap feedwater pumps.
- On November 19, 2005, Unit 2 downpowered to 95 percent to swap feedwater pumps.

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 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. Specifically, the inspectors reviewed the following two system/structures:

- Primary Water Storage Tanks; and
- Essential Service Water Cooling Towers.

The inspectors walked down the primary water storage tanks, the essential service water cooling towers, and other areas of the station potentially affected by cold weather. Insulated and trace heated piping and components, operation of area space heaters, and closure of outside air dampers were inspected. The inspectors selected the two structures listed because they were identified as risk significant in the licensee's risk analysis. 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.

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 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 walkdown samples 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 determine 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 determine that there were no obvious deficiencies. The inspectors used the information in the appropriate sections of the UFSAR and Technical Specification (TS) to determine the functional requirements of the systems.

The inspectors verified the alignment of the following:

- Unit 2 Station Air Compressors while 1B Auxiliary Feedwater System was out of service for maintenance; and
- Unit 1 Train A Essential Service Water System.

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

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

During the inspection, the inspectors completed one complete system alignment inspection of the accessible portions of the Unit 1 Auxiliary Feedwater system. 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:

- Unit 1 Train A Containment Spray Pump during the 1B Containment Spray Pump work window.

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

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Walkdowns

a. Inspection Scope

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

- OP-AA-201-006; Control of Temporary Heat Sources, Revision 0;
- OP-AA-201-009; Control of Transient Combustible Material, Revision 4; and
- OP-MW-201-007; Fire Protection System Impairment Control, Revision 3.

The inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and that fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The Byron Station Pre-Fire Plans applicable for each area inspected were used by the inspectors to determine approximate locations of firefighting equipment.

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

- Unit 2 Containment (Zone 1.1-2, Zone 1.2-2 and Zone 1.1-3);
- Unit 1 Auxiliary Feedwater Tunnel & Main Steam Tunnel (Zone 18.3-1);
- Turbine Building 451' (Zone 8.6-0);
- Division 12 4KV Switchgear Room (Zone 5.1-1);

- Division 12 Misc. Electrical Equipment Room (Zone 5.4-1);
- Auxiliary Building 401' Elevation General Area (zone 11.5-0);
- Unit 2 Train B Auxiliary Feedwater Pump Room (Zone 11.4A-2);
- Lower Cable Spreading Room (Zone 3.2A-1);
- Unit 2 Auxiliary Electrical Room (Zone 5.5-2); and
- Unit 2 2A Diesel Generator Room (Zone 9.2-2).

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

b. Findings

No findings of significance were identified.

.2 Drill Observation

a. Inspection Scope

The inspectors assessed the fire brigade performance and the drill evaluator's critique during a fire brigade drill conducted on November 18, 2005. This was not counted as an inspection sample since the required annual sample had been completed. The inspectors determined that this drill was of importance since it involved local fire department participation. The drill simulated an airplane crash in the protected area. The inspectors focused on command and control of the fire brigade activities; fire fighting and communication practices; material condition and use of fire fighting equipment; implementation of pre-fire plan strategies, the coordination of fire fighting actions between station fire brigades and offsite resources and access control of offsite resources. The inspectors evaluated the fire brigade performance using the licensee's established procedures and guidance.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

During the week of October 31, 2005, the inspectors evaluated the licensee's controls for mitigating internal flooding by completing a semi-annual sample. The specific areas evaluated included the auxiliary building elevations 330', 346', and 364'. During the evaluation, inspectors performed the following:

- Reviewed the licensee's design basis documents including UFSAR, and Safety Evaluation Report, to identify the design basis for flood protection and to identify those areas susceptible to internal flooding;

- Interviewed members of the licensee engineering and operations staff in regards to system design and flood response actions;
- Reviewed selected abnormal operating procedures for identifying and mitigating flooding events;
- Reviewed plant configuration that may impact external flooding controls;
- Inspected areas for control of materials that could potentially clog drains; and
- Inspected the watertight doors and flood seals.

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

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

.1 Annual Sample of Heat Sink Performance (71111.07A)

a. Inspection Scope

The inspectors completed one annual testing and performance review inspection sample by observing and evaluating the licensee’s inspection of the following safety-related heat exchanger:

- Unit 2, Train B Auxiliary Feedwater Right Angle Lube Oil Cooler.

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

In addition to observing the inspection and reviewing the heat exchanger inspection results, the inspectors discussed the results and heat exchanger performance with the licensee’s engineer responsible for the heat exchanger inspection program.

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

b. Findings

No findings of significance were identified.

.2 Biennial Review of Heat Sink Performance (71111.07B)

a. Inspection Scope

The inspectors reviewed the performance of the Unit 1 service water pump room cooler and lube oil cooler, and the Unit 2 emergency diesel generator engine jacket water cooler (a total of three heat exchangers). These heat exchangers were chosen for review based on their high risk achievement worth in the licensee's probabilistic safety analysis. This review resulted in the completion of three inspection samples. While onsite, the inspectors reviewed completed surveillance tests, and associated calculations. The inspectors reviewed the documentation to confirm that the test and/or inspection methodology was consistent with accepted industry and scientific practices. This review was based on heat transfer texts and an Electrical Power Research Institute standard (EPRI NP-7552, "Heat Exchanger Performance Monitoring Guidelines"). The inspectors also reviewed documentation to verify that acceptance criteria was consistent with design basis values, as outlined in the UFSAR and TS. The inspectors reviewed documentation to verify that the licensee took appropriate actions to verify physical integrity of the heat exchangers. The inspectors also reviewed documentation to verify that the licensee had appropriate controls in place to ensure availability of the ultimate heat sink under adverse conditions.

The inspectors 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 inspectors also evaluated the effectiveness of the corrective actions for identified issues, including the engineering justification for operability.

The documents that were reviewed are included in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08)

.1 Piping Systems ISI

a. Inspection Scope

The inspectors conducted a review of the implementation of the licensee's ISI program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries for Unit 2. The inspectors selected components based upon the ISI activities available for review during the onsite inspection period.

The inspectors observed the following two types of nondestructive examination activities to evaluate compliance with the ASME Code Section XI and Section V requirements and to verify that indications and defects (if present) were dispositioned in accordance with the ASME Code Section XI requirements.

- Ultrasonic examination (UT) of two feedwater system welds (2FW03DD-16, C01, C02) on a 16 inch diameter line in the Unit 2 main steam isolation valve (MSIV) room, five feedwater system welds (2FW87CA-6, C05, C06, C07, C08, C09) outside the missile barrier inside containment and three reactor coolant system welds (2RC28A-3, J03, J04, J05) inside the missile barrier within containment; and

- Magnetic particle examination of a support weld (2MSS07AD-28, E-2) for a 28 inch main steam line located in the MSIV room.

The inspectors reviewed a Code VT-3 examination from the previous outage with relevant indications identified on snubber support 2RC18001S to determine if the licensee's corrective actions and extent of condition reviews were in accordance with the ASME Code requirements.

The inspectors reviewed pressure boundary welds for the Code Class 2 and 3 portions of the Unit 2 residual heat removal (RH) system, to determine if the welding acceptance and preservice examinations (e.g., pressure testing, visual, dye penetrant, and weld procedure qualification tensile tests and bend tests) were performed in accordance with ASME Code Sections III, V, IX, and XI requirements. Specifically, the inspectors reviewed records of six field welds associated with the installation of two new valves and piping components in a 3 inch diameter line within the RH system.

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

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

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

The reviews as discussed above counted as one inspection sample.

b. Findings

Introduction: The inspectors identified a finding involving a Non-Cited Violation (NCV) of 10 CFR Part 50.55a(g)(4)ii having very low safety significance (Green) for failure to perform a VT-2 examination at nominal operating pressure for six new RH system welds returned to service.

Description: On September 28, 2005, the inspectors identified that the licensee had not completed a VT-2 examination at nominal operating system pressure upon returning six newly fabricated pressure boundary welds in a 3 inch RH system line to service.

Following construction of a new weld in a safety-related Code Class 1, 2 or 3 system, a VT-2 examination is required at hydrostatic test pressure as specified by article IWA-4000 of Section XI of the ASME Code. As an alternative to completing a VT-2 examination at hydrostatic test pressure, the licensee elected to implement Code Case 416-1 and substitute a VT-2 examination at nominal operating pressure and temperature for six new RH system welds installed under work order No. 00366731.

During shutdown cooling the RH system operates at pressures up to 350 pounds per square inch gage (psig). On September 18, 2003, the licensee returned six newly fabricated welds to service in accordance with work order No. 00366731 and performed a VT-2 examination with the system at only 50 psig. Subsequently, on five occasions during RH pump surveillance testing, the licensee subjected these welds to pressures exceeding 200 psig without performing VT-2 examinations. The inspectors were concerned that subjecting these new welds to pressures above that previously tested without examination could have resulted in undetected leakage associated with a weld defect or failure. On March 23, 2004, the licensee performed a preplanned VT-2 examination of the six new RH system welds with system pressure at 350 psig with no evidence of weld leakage. The licensee performed this test to fulfill the Code Case 416-1 requirements as documented on a Code NIS-2 data form. However, the licensee staff did not recognize that these welds had been subjected to pressures above that seen during the initial VT-2 examination. Because, the licensee had not completed a VT-2 examination at 350 psig prior to, or immediately upon return of these welds to service, the inspectors determined that the requirements of paragraph (b) of Code Case 416-1 had not been met.

Analysis: The inspectors determined that the failure of the licensee to perform a VT-2 examination of six RH system welds at nominal operating system pressure prior to, or immediately upon return to service was a performance deficiency that warranted a significance evaluation. This finding was of more than minor significance because the licensee returned these six welds to service without completing a VT-2 examination at the required pressure, which placed the RH system (mitigating system) at increased risk for undetected leakage and component failure. Therefore, operation of the RH system with improperly tested piping affected the mitigating system cornerstone objective of equipment reliability. This finding was of very low safety significance because a VT-2 examination at the required pressure was subsequently completed with all welds passed. The inspectors determined that the finding could not be evaluated using the Significance Determination Process (SDP) in accordance with NRC IMC 0609, "Significance Determination Process," because the SDP for the Mitigating Systems Cornerstone applied to degraded systems/components, not to the testing and examination activities intended to detect degraded components. Therefore, this finding was reviewed by a Regional Branch Chief in accordance with IMC 0612, Section 05.04c, who agreed with the inspectors that this finding was of very low safety significance.

Enforcement: On September 28, 2005, while performing the NRC baseline procedure 71111.08, the inspectors identified an NCV of 10 CFR Part 50.55a(g)(4)ii.

10 CFR 50.55a(g)(4)ii requires compliance with Section XI Edition of the ASME Code issued within 12 months of the start of the interval or the ASME Code Cases identified in Regulatory Guide 1.147 for examination of components and system pressure tests.

Regulatory Guide 1.147 identified Code Case 416-1 as an NRC approved Code Case.

Paragraph (b) of Code Case CC 416-1 required that prior to or immediately upon return to service, a visual examination VT-2 shall be performed at nominal operating pressure.

Contrary to these requirements, on September 18, 2003, the licensee returned six RH system welds (Code Class 2 and 3 system) to service under work order No. 00366731 without performing VT-2 examination at nominal operating pressure. This violation existed until March 23, 2004, when these welds were subjected to a VT-2 examination at nominal operating pressure. The finding was not suitable for SDP evaluation, but has been reviewed by NRC Management and has been determined to be a Green finding of very low safety significance. Because of the very low safety significance of this finding and because the issue was entered into the licensee's corrective action program (AR 00380389), it is being treated as an NCV, consistent with Section VI.A.1 of the Enforcement Policy (NCV 05000455/2005011-01).

.2 Pressurized Water Reactor Vessel Head Penetration ISI

a. Inspection Scope

The inspectors conducted a review of the licensee's activities associated with a bare metal visual examination of the Unit 2 reactor vessel head and vessel head penetration nozzles to meet NRC Order EA 03-009. Specifically, the inspectors observed the licensee performing direct and remote VT-2 type examinations of portions of five vessel head penetration nozzles and reviewed the video-taped examination records for other penetration locations. Additionally, the inspectors completed an independent direct visual examination for portions of six peripheral vessel head penetration nozzle locations and reviewed the final written examination records documenting the extent of the licensee's visual examination coverage.

The inspectors completed these reviews and observations to confirm that the licensee had criteria for visual examination quality, appropriately resolved interference or masking issues, dispositioned indications and defects in accordance with the ASME Code (if present), and that the examination scope met the requirements of NRC order EA-03-009.

Procedure 71111.08, Steps 02.02.c and 02.02.d associated with recordable indications accepted for continued service and welded repairs were not performed because no recorded indications had been identified and no welded repairs had been completed. Therefore, inspectors concluded that the reviews discussed above did not count as a completed inspection sample as described in Section 71111.08-5 of the inspection procedure, but the sample was completed to the extent possible.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control (BACC) ISI

a. Inspection Scope

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

The inspectors observed the licensee during BACC visual examinations of the reactor coolant and other borated systems conducted on September 25, 2005, to evaluate compliance with licensee BACC program requirements and 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requirements. In particular, the inspectors observed these examinations to determine if the licensee focused on locations where boric acid leaks could cause degradation of safety significant components and that degraded or non-conforming conditions were properly identified in the licensee’s corrective action system.

The inspectors reviewed engineering evaluations performed for boric acid found on reactor coolant system piping and components to verify that the minimum design code required section thickness had been maintained for the affected component(s). Specifically, the inspectors reviewed:

- Evaluation No. 2004-315 for Component 2CV128, Minor Packing Leak;
- Evaluation No. 2004-466 for Component 2RH029A, Valve Cap found Leaking at ½ Drop per Second; and
- Evaluation No. 2004-404 for Component 2SI121A, Boric Acid Leak at Base of Relief Valve.

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

- AR 00377795, Body to Bonnet Leakage from 2RC8045D, September 26, 2005;
- AR 00379178, Boric Acid Packing Leak, Dry 2CV236, September 29, 2005; and
- AR 00381103, Boric Acid Leakage at Kerotest Check Valve Cap, October 3, 2005.

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

b. Findings

No findings of significance were identified.

.4 Steam Generator (SG) Tube ISI

a. Inspection Scope

The inspectors performed an on-site review of SG tube examination activities conducted pursuant to TS and the ASME Code Section XI requirements.

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

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

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

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

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

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

The inspectors also reviewed licensee in-situ pressure test results for tube R49-C50, which was pressure tested during the Byron Unit 2 Refueling Outage No. B2R11. The inspectors performed this review to determine if the in-situ SG tube pressure testing screening criteria and test pressures were consistent with EPRI TR-107620, "Steam Generator In Situ Pressure Test Guidelines."

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

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

- Procedure 71111.08, Steps 02.04.a.3 and 02.04.a.4 associated with review of in-situ pressure testing and tube performance criteria were not available for review because none of the degraded SG tubes examined during the current refueling outage No. 12 met the screening requirements for pressure testing.
- Procedure 71111.08, Step 02.04.d associated with review of licensee activities for new SG tube degradation mechanisms was not available for review because no new tube degradation mechanisms were identified; and
- Procedure 71111.08, Step 02.04.h associated with review of corrective actions for primary-to-secondary leakage greater than 3 gallons per day was not available for review because primary-to-secondary leakage was below the minimum detectable threshold during the previous operating cycle.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Resident Inspector Quarterly Review

a. Inspection Scope

The inspectors completed one inspection sample by observing and evaluating an operating crew during an Anticipated Transient Without Scram (ATWS) requiring a manual reactor shutdown. 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 1;
- OP-AA-103-102, Watchstanding Practices, Revision 3;
- OP-AA-103-103, Operation of Plant Equipment, Revision 0; 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 determine whether they also noted the issues and discussed them in the critique at the end of the session.

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

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors completed one inspection sample 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 structures, systems, and/or components:

- Unit 2, 2D Reactor Coolant Pump motor move to Unit 2 containment with fuel in the core.

The inspectors evaluated the licensee's appropriate handling of SSC condition problems in terms of appropriate work practices and characterizing reliability issues. Equipment problems were screened for review using a problem oriented approach. Work practices were observed which related to the reliability of equipment maintenance during the inspection period. Items chosen are risk significant, and extent of condition was reviewed as applicable. Work practices were reviewed for contribution to potential degraded conditions of the affected SSCs. Related work activities were observed and corrective actions were discussed with licensee personnel. Exelon's handling of the issues being reviewed were evaluated under the requirements of the maintenance rule

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 are listed in the Attachment to this report.

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

a. Inspection Scope

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

The inspectors reviewed configuration risk assessment records, UFSAR, TS, and Individual Plant Examination. The inspectors also observed operator turnovers, observed plan-of-the-day meetings, and reviewed other related documents to determine 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 documents:

- ER-AA-600, Risk Management, Revision 4;
- ER-AA-310, Implementation of the Maintenance Rule, Revision 4;
- OU-AA-103, Shutdown Safety Management Program, Revision 4;
- OU-AP-104, Shutdown Safety Management Program, Revision 8;
- WC-AA-101, On-Line Work Control Process, Revision 11;
- Byron Operating Department Policy 400-47, June 23, 2004, Revision 7; and
- Byron Nuclear Power Station Probabilistic Risk Assessment, Revision 5B.

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

- Unit 1 Train A Auxiliary Feedwater pump work window concurrent with Unit 1 Train A Station Air maintenance;
- Emergent work on the Feedwater Isolation Valve 2FW009C;
- Emergent work on the 1A Emergency Diesel Generator;
- Planned maintenance on the Essential Service Water makeup pump concurrent with Auxiliary Building HVAC maintenance; and
- Unit 1 Solid State Protection System Surveillance while a Main Control Room Door was removed for maintenance.

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 are listed in the Attachment to this report.

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 two inspection samples by observing or evaluating control room and equipment operators during the following non-routine evolutions:

- Unit 2 startup testing from the B2R12 outage; and
- Unit 2 reactor trip.

The inspectors evaluated crew performance in the areas of:

- 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;
- OP-AA-103-102, Watchstanding Practices;
- OP AA-103-103, Operation of Plant Equipment; and
- OP-AA-104-101, Communications.

Additional documents reviewed during this inspection are listed under Section 4OA3 of the Attachment to this report.

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 two inspection samples by reviewing the following evaluations and issues:

- Unit 1Train B Emergency Diesel Generator undervoltage relay failed surveillance criteria; and
- Unit 2 Feedwater Isolation Valve 2FW009C failed inservice testing.

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 determine that the components or systems were operable. The inspectors determined whether compensatory measures, if needed, were taken, and determined whether the evaluations were consistent with the requirements of licensee's Procedure LS-AA-105, "Operability Determination Process," Revision 1. The inspectors also discussed the details of the evaluations with the shift managers and appropriate members of the licensee's engineering staff.

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

- NRC Inspection Manual Part 9900, Technical Guidance, Operability Determinations & Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Averse to Quality or Safety; September 26, 2005; and
- NRC Regulatory Issue Summary RIS-05-020, Revision to Guidance Formerly Contained in NRC Generic Letter 91-18, Information to Licensees regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability.

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 are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors completed one operator workaround sample. The inspectors evaluated the impact of an existing operator challenge and corrective actions taken or proposed to correct the problem:

- Unit 1, 1D Main Steam Isolation Valve high Pressure Alarm.

During this review, the inspectors interviewed operating and engineering department personnel and reviewed applicable documents.

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

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modification (71111.17)

a. Inspection Scope

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

- Unit 2 Digital Electrohydraulic System Modification

The inspectors reviewed the digital electrohydraulic system modification installed during B2R12 to verify that the design basis, licensing basis, and performance capability of risk significant systems were not degraded by the installation of the modification. The inspectors considered the design adequacy of the modification by performing a review of the modification's impact on plant electrical requirements, material requirements and replacement components, response time, control signals, equipment protection, operation, failure modes, and other related process requirements.

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

- Updated Final Safety Analysis Report; and
- Technical Specifications.

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

b. Findings

Introduction: A finding having very low safety significance (Green) was self-revealed when the recently modified Digital Electrohydraulic System failed to respond to operator input to initiate a turbine runback and subsequently resulted in a reactor trip. The failure was due to a software error missed during the modification review and testing.

Description: From September 25 through October 12, 2005, Unit 2 conducted refueling outage B2R12 during which the Digital Electrohydraulic (DEH) system was modified. On October 18, 2005, with Unit 2 at full power, the operators removed the 2D condensate/condensate booster (CD/CB) pump from service for planned maintenance. Several hours later on October 19, 2005, the 2A CD/CB pump tripped and the operators executed procedure 2BOA SEC-1, "Secondary Pump Trip." Per procedure, the operators tried to initiate turbine runback through the newly modified DEH system. However, the system failed to respond to operator input. A load reduction was then initiated by placing the turbine in manual and rapidly closing the turbine governor valves to about 24 percent. However, by this time steam generator levels were approaching the Reactor Protection System (RPS) trip setpoint. The operators then initiated actions to trip the reactor but a reactor trip from low steam generator level was actuated by RPS before the manual trip was accomplished.

Following the reactor trip, the licensee determined that the algorithm required for turbine runback was deleted from the software database due to a compiler fault. An undocumented length limitation on the software code caused the compiler fault. The vendor and the licensee did not realize this limitation even though an error log existed after compilation. In addition, the licensee did not test the turbine runback function at power. The licensee also determined that the same condition existed in Unit 1 since the DEH system was modified in March 2005. Based on these shortcomings in verification and testing, the inspectors considered the post maintenance testing of the DEH modification to be inadequate and contributed to a reactor trip.

Analysis: The inspectors determined that the failure to discover the software error for the DEH modification was a performance deficiency because the licensee's modification process specified the need to perform post modification testing and because it was within the licensee's ability to foresee and prevent the error. Traditional enforcement did not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements or licensee's procedures. This finding warranted a significance evaluation in accordance with Inspection Manual Chapter (IMC) 0612 "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening" issued on September 30, 2005. The inspectors determined that the finding was more than minor because it affected the design control attribute of the Initiating Events cornerstone. The initiating Events cornerstone objective is to limits the likelihood of those events that upset plant stability and challenge critical safety functions during at-power operations as the lack of turbine runback capability contributed to a reactor trip from a feedwater system transient.

The inspectors determined that the finding could be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, "Significance Determination Process," because the finding was associated with the transient initiator contributors of the Initiating Events cornerstone. The finding was determined to be of very low safety significance (Green), since it only contributed to the likelihood of a reactor trip.

Enforcement: There were no violations of NRC regulatory requirements because the affected equipment was not safety-related. The licensee entered this finding into their corrective action program as AR 387581 and subsequently reinstalled the missing software algorithm into both Unit 1 and Unit 2 DEH systems.
(FIN 05000455/2005011-02)

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 determine 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, and other related documents to evaluate this area. The inspectors verified that the licensee controlled post maintenance testing in accordance with the following:

- BAP 1600-11, Work Request Post Maintenance Testing Guidance, Revision 12; and
- MA-AA-716-012, Post Maintenance Testing, Revision 5.

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

- Unit 2 Train B RH Suction from Sump Isolation Valve;
- Unit 2 Train A Centrifugal Charging Pump;
- Unit 1 Train A Emergency Diesel Generator Voltage Regulator Repair;
- Unit 1 Train B Emergency Diesel Generator Output Relay failure and
- Unit 1 Essential Service Water Discharge Cross-Tie Isolation Valve Breaker Replacement.

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

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors observed the licensee's performance during B2R12 conducted October 1, 2005 through October 12, 2005. This inspection sample was carried over from last quarter.

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 plant configuration to verify that the licensee maintained defense-in-depth commensurate with the shutdown risk plan; reviewed major outage activities to ensure that correct system lineups were maintained for key mitigating systems; and observed refueling activities to ensure that fuel handling operations were performed in accordance with 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 Reasonably Achievable] briefings. Other major outage activities evaluated included the licensee's control of:

- Containment penetrations in accordance with the TS;
- Structures, systems for components (SSCs) which could cause unexpected reactivity changes;
- Flow paths, configurations, and alternate means for reactor coolant system inventory addition;
- SSCs which could cause a loss of inventory;
- Reactor coolant system 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 the shutdown risk plan; and
- SSCs required for decay heat removal.

The inspectors observed portions of the plant startup, including the transition from Mode 3 to Mode 2, to verify that the licensee controlled the plant startup and testing in accordance with the TS. In addition, the inspectors completed numerous visual inspections inside the Unit 2 containment. This included a tour of the Unit 2 containment at Mode 3 before startup so that the inspectors could assess the material conditions of equipments inside containment before the start of an operating cycle. During the visual inspections the inspectors focused on the material condition of the equipment and particularly on any indication of boric acid leakage.

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

- ER-AP-331-1002; Boric Acid Corrosion Program Identification, Assessment, and Evaluation;
- HU-AA-104-101; Procedure Use and Adherence;
- OP-MW-109-101; Clearance and Tagging;
- OU-AA-103; Shutdown Safety Management Program;
- OU-BY-204; Fuel Handling Activities in the Spent Fuel Pool for Byron and Braidwood; and
- OU-BY-205; Fuel Handling Activities in Containment During Refuel Outages for Byron and Braidwood.

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

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors witnessed selected surveillance testings and/or reviewed test data to determine that the equipment tested using the surveillance procedures met the TS, the TRM, the UFSAR and licensee procedural requirements. The inspectors also reviewed applicable design documents including plant drawings, to verify 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 ensuring mitigating systems capability and barrier integrity.

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

- Unit 2 Flow Balance of Charging and Safety Injection System to Cold Leg;
- Unit 2 Train B Safety Injection Pump Discharge Outside Containment Isolation Valve Stroke and Position Indication Test; and
- Unit 2 Containment Floor Drain Level Transmitter Calculation.

Additionally the inspectors used the documents listed in the Attachment to this report to determine that the testing met the frequency requirements; that the tests were conducted in accordance with procedures that the test acceptance criteria were met; and that the results of the tests were properly reviewed and recorded. The inspectors verified that the individuals performing the tests were qualified to perform the test in accordance with the licensee’s requirements, and that the test equipment used during the test were calibrated within the specified periodicity. In addition, the inspectors interviewed operations, maintenance and engineering department personnel regarding the tests and test results.

The inspectors also reviewed selected issues documented in CR’s, to determine if they had been properly addressed in the licensee’s corrective action program. The documents reviewed during this inspection are 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:

- Removal of Tachometer Pickup Guard from Diesel Generator 1B.

The inspectors reviewed this temporary plant modification to determine 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 Nuclear Station Procedure NSP CC-AA-112, "Temporary Configuration Changes," Revision 9.

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

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspectors performed a screening review of Revision 16 of the Byron Station Emergency Plan Annex to determine whether the changes made in Revision 16 decreased the effectiveness of the licensee's emergency planning. This screening review of Revision 16 was not documented in a Safety Evaluation Report and does not constitute an approval of the changes. Therefore, the changes are subject to future NRC inspection to ensure that the emergency plan continues to meet NRC regulations.

These activities completed one inspection sample.

b. Findings

Introduction: The licensee changed one Emergency Action Level (EAL) that addressed events related to unplanned radiological releases. This change was determined to decrease the effectiveness of the licensee's emergency plan, however, the licensee did not submit this change to NRC for prior approval. This is a violation of 10 CFR 50.54(q) and, because it impacted the regulatory process, traditional enforcement was applied. Since this issue was entered into the licensee's corrective action program and because this item involved a failure to meet a regulatory requirement not directly related to assessment or notification, this issue was determined to be a Severity Level IV Non-Cited Violation (NCV).

Description: The licensee's site-specific EALs were based on the guidance in NUMARC/NRSP-007. In 1995, the licensee upgraded the RU2 EAL threshold value to include criteria for confirming the validity of the effluent radiation monitor release indications within 15 minutes by comparison with greater than or equal to two times the Offsite Dose Calculation Manual limit. An Unusual Event would not be declared if the comparison did not support the effluent monitors' indication of a release. Revision 15 to the Byron Station Emergency Plan Annex reflected this 15-minute criteria and appeared as follows:

Revision 15 RU2 EAL Threshold Value In Part:

> Unplanned Radiological release in excess of Table R1 “Unusual Event” value unless releases can be determined to be below available Table R2 “Unusual Event” thresholds within 15 minutes.

Revision 16 RU2 Threshold Value In Part:

> Unplanned radiological release in excess of Table R1 “Unusual Event” threshold for $\geq$60 minutes UNLESS release can be determined to be below available Table R2 “Unusual Event” thresholds within this period.

Discussions with the licensee emergency preparedness staff and inspection of the 10 CFR 50.54(q) review records indicated this change was made to rearrange the EAL with the more accurate indicators first and due to control room crews’ interpretation that they had 75 minutes to declare an Unusual Event in this EAL. Also, the licensee’s 10 CFR 50.54(q) review indicated that the change did not decrease the effectiveness of the emergency plan.

In contrast, the inspectors determined that the change to this indicator represented a decrease in effectiveness of the emergency plan because the re-worded EAL threshold removed the NRC’s 1995 approved 15-minute requirement and replaced it with a 60-minute requirement for determining whether releases were below specified effluent monitor thresholds.

The requirements of 10 CFR 50.54(q) allow the licensee to make changes to the emergency plan without Commission approval as long as the change does not decrease the effectiveness of the emergency plan. The inspectors noted that this change could potentially delay the declaration of an Unusual Event by as much as 45 minutes. However, since the licensee had concluded in its 10 CFR 50.54(q) review that the change to this EAL threshold did not decrease the effectiveness of the emergency plan, this change was not submitted to the NRC for review prior to implementation of the revised EAL threshold.

Analysis: The inspectors determined that the failure to request NRC approval of the EAL change was a performance deficiency. Furthermore, the failure to request NRC approval of the EAL change potentially impeded the NRC’s regulatory process and was therefore, in accordance with Section 2.2.e of Appendix B to NRC Manual Chapter 0609, evaluated using the guidance in Section IV of NUREG-1600, General Statement of Policy and Procedure for NRC Enforcement Actions (Enforcement Policy), rather than the NRC Significance Determination Process (SDP). This finding was more than minor because extending the time period required for the appropriate emergency classification of a radiological release could adversely affect the performance of both onsite and offsite emergency actions. The finding is not suitable for SDP evaluation, but has been reviewed by NRC management. The finding was therefore dispositioned as a Severity Level IV violation according to Supplement VIII (Emergency Preparedness) of the Enforcement Policy because it involved the licensee’s failure to meet an emergency planning requirement (namely, 10 CFR 50.54(q)) not directly related to assessment of and notification.

Enforcement: 10 CFR 50.54(q) states, in part, that the "licensee may make changes to these plans without Commission approval only if the changes do not decrease the effectiveness of the plans. Proposed changes that decrease the effectiveness of the approved emergency plans may not be implemented without application to and approval by the Commission." Contrary to this, in Revision 16 of the Byron Station Emergency Plan Annex, the licensee made a change to its standard EAL scheme that reduced the effectiveness of the emergency plan. This change was not submitted to the NRC for approval prior to implementation. The licensee entered this issue into their corrective action program as Condition Report (CR) 00437193.

Changing an emergency plan commitment without prior NRC approval impacts the NRC's ability to perform its regulatory function and is therefore processed through traditional enforcement, as specified in Section IV.A.3 of the Enforcement Policy, issued May 1, 2000 (65 FR 25388). According to Supplement VIII of the Enforcement Policy, this finding was determined to be a Severity Level IV because it involved a failure to meet a requirement not directly related to assessment and notification. Further, this problem was isolated to one EAL and was not indicative of a functional problem with the licensee's EAL scheme. Additionally, because this was a Severity Level IV violation and the licensee entered this issue into its corrective action program, this finding is being treated as Non-Cited Violation (Severity Level IV) consistent with Section VI.A.1 of the Enforcement Policy. (NCV 50-454/05-11-01).

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

On November 14, 2005, the inspectors completed one inspection sample by observing an Emergency Preparedness drill. 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 drill scenario observed was:

- Loss of offsite power to unit 1 and partial loss of offsite power to Unit 2 and security event.

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

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

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

a. Inspection Scope

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

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

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

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

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

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

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions;
- Resolution of NCVs tracked in the corrective action system; and
- Implementation/consideration of risk-significant operational experience feedback.

This review represented one sample.

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

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

b. Findings

No findings of significance were identified.

.4 Radiation Worker Performance

a. Inspection Scope

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

b. Findings

No findings of significance were identified.

.5 Radiation Protection Technician Proficiency

a. Inspection Scope

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

b. Findings

No findings of significance were identified.

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

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective exposure history, current exposure trends along with ongoing and planned activities in order to assess current performance and exposure challenges. This included determining the plant's current 3-year rolling average collective exposure. This review represented one sample.

Site specific trends in collective exposures and source-term measurements were reviewed to evaluate the effect of the plant's source term on worker exposure. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the assumptions and bases for the current annual collective exposure estimate. Procedures were reviewed in order to evaluate the licensee's methodology for estimating work activity-specific exposures and the intended dose outcome. Dose rate and man-hour estimates were evaluated for reasonable accuracy. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

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

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

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

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the 2003 and 2004 annual Radiological Environmental Operating Reports and licensee assessment results to determine if the radiological environmental monitoring program (REMP) was implemented as required by the Radiological Environmental TSs (RETS) and the ODCM. The inspectors reviewed the report for changes to the ODCM with respect to environmental monitoring and commitments in terms of sampling locations, monitoring and measurement frequencies, land use census, interlaboratory comparison program, and data analysis. The inspectors reviewed the ODCM to identify environmental monitoring stations and evaluated licensee self-assessments, audits, licensee event reports, and interlaboratory comparison program results. The inspectors reviewed the UFSAR for information regarding the environmental monitoring program and meteorological monitoring instrumentation. The inspectors also reviewed the scope of the licensee's audit program to determine if it met the requirements of 10 CFR 20.1101c. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Onsite Inspection

a. Inspection Scope

The inspectors accompanied the REMP vendor representative during his weekly sample collection surveillance of all eight environmental air sampling stations and 16 of the 40 environmental thermoluminescent dosimeters to verify that their locations were consistent with their descriptions in the ODCM and to evaluate the material condition of these stations. This review represented one sample.

The inspectors observed the collection and preparation of a variety of environmental samples including ground and surface water, and air. They also observed the technician perform air sampler field check maintenance to determine if the air samplers were functioning in accordance with vendor and licensee procedures. The inspectors determined if environmental sampling was representative of the release pathways as specified in the ODCM and that sampling techniques were in accordance with procedures. This review represented one sample.

The meteorological monitoring site was observed and meteorological equipment maintenance records were reviewed to evaluate the condition of the meteorological instruments and to determine if the equipment was operable, calibrated, and maintained in accordance with guidance contained in the UFSAR, annual report, NRC Safety Guide 23, and licensee procedures. The inspectors reviewed the 2003 and 2004 Annual Radiological Environmental Operating Reports and a sampling of monthly reports to evaluate the onsite meteorological monitoring program’s data recovery rates, routine calibration, and maintenance activities. The inspectors determined if the meteorological data readout and recording instruments, including computer interfaces and data loggers, at the tower were operable; that readouts of wind speed, wind direction, delta temperature, and atmospheric stability measurements were available on the licensee’s computer system which was available in the control room, and that the computer system was operable. This review represented one sample.

The inspectors reviewed each event documented in the Radiological Environmental Operating Reports which involved missed samples, inoperable samplers, lost thermoluminescent dosimeters, or anomalous measurements for the cause and corrective actions. The licensee’s assessment of positive sample results (i.e., licensed radioactive material detected above the lower limits of detection) were reviewed along with the associated radioactive effluent release data that was the likely source of the released material. This review represented one sample.

The inspectors reviewed the ODCM for significant changes resulting from land use census modifications, or sampling station changes made since the last inspection. This included a review of technical justifications for changed sampling locations. The inspectors also determined if the licensee performed the reviews required to ensure that the changes did not affect their ability to monitor the impacts of radioactive effluent releases on the environment. This review represented one sample.

Calibration and maintenance records for the eight air samplers were reviewed to determine if the equipment was being maintained as required. The inspectors reviewed calibration records for radiation measurement (counting room) instrumentation that could be used for environmental sample analysis and verified that the appropriate detection sensitivities would be utilized for counting samples, in that the instrumentation could achieve the RETS/ODCM required environmental lower level of detection. The inspectors reviewed quality control data used to monitor radiation measurement instrument performance, and actions taken for degrading detector performance.

The inspectors reviewed a licensee audit of the vendor laboratory that analyzed the licensee’s REMP samples as the licensee does not perform radio-chemical analyses of REMP samples. Additionally, results of the vendor’s interlaboratory comparison program were reviewed to evaluate the effectiveness of the vendor’s analytical and quality assurance programs. Corrective actions for deficiencies identified in the audit were reviewed along with the vendor’s interlaboratory comparison program to verify the adequacy of the vendor’s analytical and quality assurance programs.

The inspectors also evaluated the results of the licensee’s interlaboratory comparison program to evaluate the adequacy of radio-chemical analyses performed by the licensee. Licensee quality assurance audit results of the REMP were reviewed to determine whether the licensee met the TS/ODCM requirements. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Unrestricted Release of Material from the Radiologically Restricted Area

a. Inspection Scope

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

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

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

b. Findings

No findings of significance were identified.

.4 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed self-assessments, audits, condition reports, and special reports related to the radiological environmental monitoring program since the last REMP inspection to determine if identified problems were entered into the corrective action program for resolution. This included (1) the results of recent focus area self-assessments of the REMP and Radioactive Material Control programs; (2) a Nuclear

Oversight Continuous Assessment Report and field observations; and (3) the licensee’s CR database generated in calendar years 2003 - 2005. The inspectors evaluated the effectiveness of these processes to identify, characterize and prioritize problems, and to develop and implement corrective actions. The inspectors also verified that the licensee's self-assessment program was capable of identifying and addressing repetitive deficiencies or significant individual deficiencies that were identified by the problem identification and resolution process.

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

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions;
- Resolution of NCVs tracked in the corrective action system; and
- Implementation/consideration of risk significant operational experience feedback.

This review represented one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstones: Occupational and Public Radiation Safety

.1 Radiation Safety Strategic Area

a. Inspection Scope

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

- Occupational Exposure Control Effectiveness: Units 1 and 2

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

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

  The inspectors reviewed data associated with the RETS/ODCM PI to determine if the indicator was accurately assessed and reported. This review included the licensee's condition report database for the previous four quarters, to identify any potential occurrences such as unmonitored, uncontrolled or improperly calculated effluent releases that may have impacted offsite dose. The inspectors also selectively reviewed gaseous and liquid effluent release data and the results of associated offsite dose calculations and quarterly PI verification records generated over the previous four quarters. Data collection and analyses methods for PIs were discussed with licensee representatives to determine if the process was implemented consistent with industry guidance in Revision 3 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline." This review represented one sample.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

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

b. Findings

No findings of significance were identified.

.2 Annual Sample - Root Cause Evaluation for the Contamination of 0A and 0B Essential Service Water Diesel Fuel Oil Storage Tanks

Introduction: On August 16, 2005, during a routine sampling of the diesel fuel oil storage tank for the 0A Essential Service Water Make-up Pump Diesel Engine, the licensee identified fuel oil contamination. The licensee's associated extent of condition review identified additional contamination of the 0B Essential Service Water Make-up Pump diesel fuel oil storage tank. Both Essential Service Water Pumps were declared inoperable as a result of these discoveries. The licensee's subsequent root cause analysis determined that this contamination was a result of improper tank cleaning work that had been performed in June of 2005. The licensee's root cause analysis cited inadequate work instructions, the contract procurement process, and inadequate post maintenance testing as contributors to this event.

a. Prioritization and Evaluation of Issues

(1) Inspection Scope

The inspectors reviewed the root cause evaluation associated with AR 353560 and discussed the technical aspects of these issues with members of the licensee's engineering, maintenance, and contract services staff. The licensee identified four causal factors and four contributing causes. The root cause analysis identified seven immediate, eight interim, and 12 long term corrective actions. After a review of the completed and planned corrective actions the inspectors concluded that the issues associated with this event were appropriately prioritized and adequately evaluated.

(2) Issues

The licensee determined that the tank cleaning evolution was unsuccessful due to programmatic and organizational issues. Four specific areas were noted:

- The work package development process failed to recognize tank cleaning as an activity requiring detailed instructions. The licensee relied upon the vendors previous record of successful tank cleaning, supervision, and post maintenance testing to produce the desired outcome;
- Additional Operating Experience (OPEX) citing fuel contamination as a result of cleaning activities was available but not included in the work package;
- The licensee determined that the post maintenance test for this activity did not completely address the scope of work performed. Additionally, there was no requirement for fuel oil sampling upon tank fill completion; and
- The contract requisition did not provide sufficient guidance for cleaning the fuel tanks. A review of Service Procurement Procedure SM-AC-402, Revision 0 showed the policy provided inadequate direction for the inclusion of technical scope in contract requests.

The inspectors' review of the root cause evaluation found that the licensee completed it using the analytical method of Tap Root. The inspectors considered the evaluation to be of appropriate scope and depth for the situation. The inspectors considered the associated extent of condition review to be extensive and appropriate.

b. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors assessed the licensee's immediate, interim, and long term corrective actions associated with the fuel contamination root cause investigation to determine if the corrective actions were appropriately focused to address the problems identified.

(2) Issues

The inspectors reviewed the licensee's root cause evaluation and determined that the corrective actions addressed the causes identified. Corrective actions taken by the licensee include:

- Additional detail added to work instructions for the cleaning of diesel fuel oil storage tanks;
- Additional OPEX included in work instructions;
- Review of open and ongoing contract releases and corresponding work instructions for other vendor supported activities; and
- Review and revision of contract guidance to ensure sufficient technical detail is provided for future contractor work packages.

The inspectors determined that the immediate corrective actions focused on operability concerns and were appropriate. The intermediate corrective actions addressed procedural, programmatic, and extent issues and were appropriate. In regards to the long term corrective actions, the inspectors considered them to be appropriate; however, not all of the long term actions have been implemented. Those that have been implemented lack sufficient historical depth to allow for assessment of effectiveness.

.3 Annual Sample - Essential Service Water Cooling Tower Concrete Degradation

Introduction: During this and previous report periods, the inspectors have noted a number of issues entered into the corrective action program related to concrete degradation of the circulating water natural draft cooling towers and essential service water cooling towers. Since the essential service water system provides cooling water to safety-related plant equipment under both normal and emergency conditions, the degradation of the concrete structure could affect the heat removal capability of the plant.

To access the extend of condition associated with the concrete degradation, the inspectors performed a search on the licensee's corrective action program database and reviewed selected condition reports associated with this issue. The inspectors identified that the licensee started experiencing concrete degradation in the essential service water cooling towers back in 1998 and continued with the repairs since that time. Due to the length of time that this problem existed, the inspectors selected this issue as one annual sample of the licensee's problem identification and resolution program.

Documents reviewed as part of this inspection were listed in the attachment to this report.

a. Prioritization and Evaluation of Issues

(1) Inspection Scope

The inspectors reviewed selected action requests associated with the essential service water tower concrete degradation and the related extent of condition review. The inspectors considered the licensee's evaluation and disposition of performance issues and application of risk insights for prioritization of issues.

(2) Issues

The inspectors found that the licensee prioritized and evaluated issues appropriately. No significant issues were identified in this area.

b. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed work orders associated with the concrete repair to determine if the issues were repeated and if they were resolved promptly.

(2) Issues

The inspectors determined that while concrete degradation in the cooling towers was being addressed as early as 1998, the required functions of the cooling towers were not affected due to its redundant design. However, as different modes of degradation were discovered during repair work, the repair scope had to be changed by the licensee and rescheduled, which in turn extended the work completion time. In addition, upon questioning by the inspectors, the licensee also discovered that one of the work orders for the repair work was inadvertently cancelled. This work order was reinstated.

In conclusion, the inspectors determined that the corrective actions to repair the cooling towers were adequate and they were being addressed in a timely manner. No significant issues were identified in this area.

.4 Semi-Annual Trending Review - Status of Human Performance Cross-Cutting Issue Corrective Actions and Comprehensive Improvement Program

a. Inspection Scope

During the mid-cycle assessment for the 2005 calendar year inspection program, the NRC staff identified a substantive cross-cutting issue in the area of human performance. The results of this assessment were provided to the licensee on August 30, 2005, in the Byron Mid-Cycle Performance Review letter. Per the Mid-cycle Performance Review letter, the inspectors conducted an annual inspection and trend review using Inspection Procedure 71152, “Identification and Resolution of Problems,” to focus on human performance issues.

The inspectors reviewed the licensee’s common cause analysis related to human performance issues and station clock resets, self-assessment on human performance and technical human performance, and selected departmental trend improvement plans. The inspectors discussed these programs and reports with the applicable members of the licensee’s staff.

Documents reviewed as part of this inspection were listed in the attachment to this report.

b. Issues

No findings of significance were identified. Over the course of the 2005 mid-cycle assessment period, the inspectors identified 10 findings/violations of very low safety significance (Green) where human performance was not adequate. The breakdown by cornerstone for these findings/violations was as follows:

- Initiating Events: 1 finding/violation;
- Mitigating Systems: 5 findings/violations;
- Barrier Integrity: 2 findings/violations; and
- Occupational Radiation Safety: 2 findings/violations.

Specifically, the findings/violations were attributed to inadequate human performance in manipulation of plant equipment outside of the normal work control processes, failing to comply with procedural requirements, and failure to comply with contaminated and high radiation area posting requirements.

The inspectors found that the licensee had given an appropriately high priority to the actions intended to address the substantive cross-cutting issue in human performance. Individual departmental human performance improvement plans were developed. The licensee also conducted a Focused Area Self-assessment (FASA) in June and August 2005 and a Common Cause Analysis (CCA) completed in December 2005. The licensee has also established a new human performance coordinator. The licensee did not have a station wide comprehensive improvement program, but was reviewing the comprehensive improvement program developed at LaSalle for incorporation at Byron. Many of the actions identified by the FASA and the CCA had completion dates in the November 2005 and early 2006. The results of these efforts were considered indeterminate since many of the actions were new or had not been completed. However, the actions the licensee took to make station personnel aware of the human performance problems including individual department human performance improvement plans have had some effect in reducing human performance errors. In the third and forth quarter inspection periods only two additional human performance findings/violations of very low safety significance were identified. Based on the review performed, the inspectors did not identify any additional trends.

4OA3 Event Follow-Up

.1 (Closed) Licensee Event Report (LER) 05000454, 455-2005-005-00: Both Trains of the Ultimate Heat Sink Water Makeup Trains Exceeded TS Required Action Completion Time Due to Contaminated Fuel Oil Resulting From Inadequate Tank Cleaning Procedure.

On August 16, 2005, the licensee identified that diesel fuel oil for the safety related Ultimate Heat Sink Water Makeup system diesel engine pumps contained water and sediment contamination, which rendered both trains of the makeup system inoperable. The licensee then entered into the appropriate TS limiting condition for operation (LCO), drained, cleaned, flushed, refilled, and sampled the diesel fuel oil tanks and exited the LCO. The licensee later determined that inadequate cleaning procedure and post maintenance testing requirements for the diesel fuel oil tank cleaning process for each tank in June 2005 resulting in contamination of the diesel fuel oil. The licensee evaluated the safety significance of the water makeup system inoperability and the inspectors reviewed the licensee's evaluation. The inspectors determined that this issue involved a violation of T.S. 5.4.1.a. The enforcement aspects of this issue were discussed in Section 1R12 of NRC Inspection Report 05000454/455/2005009. This met the requirements of 10 CFR 50.73 and is closed.

.2 Unit 2 Reactor Trip Response

a. Inspection Scope

On October 19, 2005, the inspectors responded to the control room after being notified that the reactor had automatically tripped from full power. The trip was caused by low steam generator level as one of the CD/CB pump developed a fault in the motor and tripped offline. The extra CD/CB pump was not available due to maintenance. A turbine runback was initiated by the Operators in an attempt to match steam flow and feed flow. However, the turbine control system failed to respond. Following the repair to the CD/CB pump, the unit returned to full power on October 22, 2005. The inspectors assessed control room operator performance immediately following the reactor trip and reviewed the post trip report.

b. Findings

No findings of significance were identified.

4OA5 Other Activities

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

a. Inspection Scope

On May 28, 2004, the NRC issued Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping

Connections at Pressurized-Water Reactors (PWR)." The purpose of this Bulletin was to:

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

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

- Request PWR licensees to provide the NRC with the information related to the inspections that have been and those that will be performed to ensure that degradation of Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections will be identified, adequately characterized, and repaired.

The objective of TI 2515/160, "Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors," was to support the NRC review of licensees' activities for inspecting pressurizer penetrations and steam space piping connections made from Alloy 82/182/600 materials, and to determine whether the inspections of these components are implemented in accordance with the licensee responses to Bulletin 2004-01. In response to Bulletin 2004-01, the licensee committed to perform a bare metal visual inspection of 100 percent of the five susceptible Inconel pressurizer penetrations in the upper pressurizer head using a VT-2 qualified examiner. On September 28, 2005, the inspector observed the licensee performing this inspection on Unit 2 and performed a review, in accordance with TI 2515/160, of the licensee's controls and personnel used for pressurizer penetration nozzles and steam space piping connections examinations to confirm that the licensee met commitments associated with Bulletin 2004-01. The results of the inspectors' review included documenting observations and conclusions in response to the questions identified in TI 2515/160.

b. <u>Observations</u>

<u>Summary</u>: Based upon a bare metal visual examination of the Unit 2 pressurizer upper head nozzles, the licensee did not identify any indications of boric acid leaks.

<u>Evaluation of Inspection Requirements</u>

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

1. For each of the examination methods used during the outage, was the examination performed by qualified and knowledgeable personnel?

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

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

   Yes. The inspectors observed the licensee performing the bare metal inspection of the pressurizer nozzles in accordance with work order 00745675 which referenced procedure ER-AP-331-1001. This procedure required licensee examination staff to use the VT-2 visual examination method in accordance with procedure, ER-AA-33-015, “VT-2 Visual Examination.” The licensee examiner conducted this inspection with a flashlight in accordance with ER-AA-33-015, and demonstrated adequate illumination on an 18 percent neutral gray card with a 1/32 inch black line. Based on ensuring adequate illumination and resolution, the inspectors considered this procedure demonstrated for the purpose of a bare metal visual examination of the pressurizer upper head nozzles.

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

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

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

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

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

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

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

   The licensee conducted a direct bare metal visual examination of these pressurizer penetrations. No video or photography equipment was used.

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

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

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

   Yes. The inspectors determined through direct observation of the licensee's efforts that the licensee staff were capable of detecting pressurizer nozzle leakage, if any had existed. The work order contained specific instructions for acceptance criteria and reporting requirements. The licensee relied on the corrective action system process to make decisions on how to characterize deposits. Because the licensee did not identify any deposits indicative of leakage in the areas examined, the inspectors could not assess the licensee's plans to characterize leakage on pressurizer components.

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

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

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

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

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

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

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

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

.2 Transportation of Reactor Control Rod Drives in Type A Packages (TI 2515/161)

a. Inspection Scope

The inspectors conducted interviews and record reviews to verify that: (1) the licensee had undergone refueling activities since calender year 2002; and (2) did not ship irradiated control rod drive mechanisms in Department of Transportation Specification 7A, Type A packages during the time frame 2002 to the present.

b. Findings

No findings of significance were identified.

.3 (Closed) Unresolved Item (URI) 5000454/2005003-06: Unverified Vessel Head Temperatures Used in Effective Degradation Year (EDY) Calculation

The inspectors had previously reviewed the licensee's Unit 1 vessel head penetration nozzle susceptibility ranking calculation to verify that it complied with NRC Order EA-03-009. During the review, the inspectors had identified that the licensee lacked reference data to support the best estimated values for vessel head temperatures used in the susceptibility ranking calculation EC-354172, "B1R13 End of Cycle 13 Effective Degradation Years In Accordance with NRC Order EA-03-009."

The inspectors reviewed the licensee's corrective actions for this issue. The licensee corrective actions for this issue included revising calculation EC-354172 to include new vessel head temperature data. The inspectors confirmed that the new data used in Revision 1 of EC-354172 was traceable to plant specific values for each operating cycle and concluded that the revised calculation met the NRC Order EA-03-009. The licensee's failure to use best estimate head temperature values in Revision 0 of calculation EC-354172, was an example of a violation of Section IV.A of NRC Order EA-03-009. Because the best estimated head temperatures changed by only a few degrees from Revision 0 to Revision 1 of EC-354172, the overall effect on the calculation output was 0.05 EDY which did not affect the head susceptibility ranking or required inspections. Therefore, the inspectors determined that this was a violation of NRC Order EA-03-009 of minor significance. URI 05000454/2005003-06 is closed. Closure of this URI also completes TI 2515/150 "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles," for Unit 1.

.4 (Closed) Unresolved Item (URI) 050000454/455/2005004-05: Review of Missed Ventilation and Filtration System TS Surveillance Requirements

On January 13, 2005, during a Nuclear Oversight Audit, the licensee identified that 15 TSs required ventilation surveillance tests were not performed. The licensee's subsequent root cause evaluation and investigation determined that the missed surveillance tests were due to willful falsification of documents by a non-licensed employee. The licensee's associated extent of condition review identified 12 additional

TS required ventilation surveillance tests that were also falsified. Upon performing the 27 falsified surveillance requirements, six failed. The NRC determined that this issue was a violation of Byron Station TSs. By providing false information regarding the surveillances, the non-licensed employee also caused the licensee to be in violation of 10 CFR 50.9, “Completeness and Accuracy of Information.” In addition, the activities of the employee also placed himself in violation of 10 CFR 50.5, “ Deliberate Misconduct.” The enforcement aspects of this issue were described in the Notice of Violation EA-05-159, “Byron Station - Notice of Violation [NRC Office of Investigations Report No. 3-2005-008,” from James L. Caldwell to Christopher M. Crane, dated October 27, 2005. This URI is closed.

4OA6 Meetings

.1 The inspectors presented the inspection results to Mr. S. Kuczynski and other members of licensee management on January 6, 2006. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Temporary Instruction 2515/160, and Procedure 71111.08 with Mr. D. Hoots and other members of licensee management at the conclusion of the inspection on October 6, 2005. The inspectors returned proprietary information reviewed during the inspection and the licensee confirmed that none of the potential report input discussed was considered proprietary;
- Radiation Protection inspection with Mr. S. Kuczynski on October 14, 2005;
- Biennial heat sink inspection with Mr. S. Kuczynski and other members of licensee management at the conclusion of the inspection on December 2, 2005; and
- Emergency Preparedness inspection with Mr. S. McCain and Mr. D. Drawbaugh by telephone call on December 28, 2005.

4OA7 Licensee Identified Violations

None.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Kuczynski, Site Vice President
D. Hoots, Plant Manager
B. Adams, Engineering Director
D. Drawbaugh, Emergency Preparedness Manager
T. Fluck, NRC Coordinator
S. Gackstetter, Operations Training Manager
T. Green, Level III NDE
W. Grundmann, Regulatory Assurance Manager
S. Kerr, Chemistry Manager
S. Koernschild, Engineering
W. Kouba, Nuclear Oversight Manager
B. McBride, ISI Engineer
S. McCain, Corporate Emergency Preparedness Manager
M. Marchionda, Shift Operations Supervisor
D. Palmer, Radiation Protection Manager
M. Prospero, Operations Manager
J. Smith, Steam Generator Engineer
M. Snow, Work Management Director
T. Spelde, Asset Management
E. Steinke, Chemistry
N. Vakili, 89-13 Program Owner
B. Youman, Maintenance Manager

Nuclear Regulatory Commission
R. Skokowski, Chief, Division of Reactor Project

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None.

Opened and Closed

05000455/2005011-01	NCV	Failure to Perform a VT-2 Examination at Nominal Operating Pressure Test for New RH System Welds (Section 1R08)
05000455/2005011-02	FIN	Failure to Perform Adequate Modification Testing for the Digital Electrohydraulic System (Section 1R17)

05000454/2005011-03 05000455/2005011-03	NCV	10 CFR 50.54(q) Violation for Decreasing the Effectiveness of the Emergency Plan by Changing EAL RU2 Threshold That Address Radiological Effluents Without Prior NRC Approval or Adequate 10CFR50.54(q) Review (Section 1EP4)

Closed

05000454-2005-005-00 05000455-2005-005-00	LER	Both Trains of the Ultimate Heat Sink Water Makeup Trains Exceeded TS Required Action Completion Time Due to Contaminated Fuel Oil Resulting From Inadequate Tank Cleaning Procedure.
05000454/2005003-06	URI	Unverified Vessel Head Temperatures Used in EDY Calculation (Section 4OA5.3)
05000454/2005004-05 05000455/2005004-05	URI	Review of Missed Ventilation and Filtration System TS Surveillance Requirements (Section 4OA5.4)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather Protection
WO 637729, Freezing Temperature Protection - Protected Area Buildings, Ventilation, and Tanks;
WO 755476, Freezing Temperature Protection - Non-Protected Area Buildings, Ventilation, and Tanks;
WO 756245-01, Freezing Temperature Protection - SX Area Heaters Testing;
WO 756245-02, Freezing Temperature Protection - SX Area Heaters Testing;
WO 755031, Freezing Temperature Protection - Auxiliary Steam Boiler Testing;
WO 755475, Freezing Temperature Protection - Plant Ventilation System;
CR 399621, Unit 2 RWST Vent Heat Trace Temperature Controller Found Mispositioned;
CR 398924, Freeze Protection - Need Gap Filled in Security Diesel Room;
CR 394858, Drain Condensate Tanks for Freeze Protection;
CR 272743, Essential Service Water Chemical Addition Piping not Insulated;
CR 265894, Louver Panel Broke, Turbine Building 401' C-23;
CR 385804, Heating Unit not Working;
CR 264434, Damaged Piping Insulation;

1R04 Equipment Alignment
OP-AA-108-112, Definition and Measurement of Mispositioned Plant Components, Revision 1;
BOP-AF-M1A, Auxiliary FEEDWATER System Train “A” Valve Lineup, Revision 3;
BOP-AF-E1A, Auxiliary Feedwater Train “A” Electrical Lineup, Revision 1;
BOP-AF-E1C, Auxiliary Feedwater Train “C” Electrical Lineup, Revision 1;
BOP-AF-E1, Auxiliary Feedwater Electrical Lineup, Revision 8;
BOP-AF-M1, Auxiliary Feedwater System Lineup, Revision 14;
BOP SA-M2C, Service Air System Valve Lineup, Revision 2;
BOP SA-E2, Service Air Electrical Lineup, Revision 3;
BOP SA-M1, Service Air System Valve Lineup, Revision 28

1R05 Fire Protection
Byron Station Pre-Fire Plan for Zone 11.5-0 Auxiliary Building 401' Elevation General Area, Revision 4;
Byron Station Pre-Fire Plan for Zone 3.2A-1, Lower Cable Spreading Room, Revision 4;
Byron Station Pre-Fire Plan for Zone 5.5-2, Unit 2 Auxiliary Electrical Room, Revision 4;
Byron Station Pre-Fire Plan for Zone 9.2-2, 2A Diesel Generator Room, Revision 4;
Byron Station Pre-Fire Plan for Zones 1.1-2, 1.2-2, 1.3-2, Containment Building;
Byron Station Pre-Fire Plan for Zone 18.3-1, Unit One Steam Tunnel;

Byron Station Pre-Fire Plan for Zone 11.4A-2, 2B Auxiliary Diesel Feedwater Pump Room;
Byron Station Pre-Fire Plan for Zone 5.4-1, Division 12 Misc Electrical Equipment and Battery Room;
Byron Station Pre-Fire Plan for Zone 5.1-1, Division 12 ESF Switchgear Room;
Byron Station Pre-Fire Plan for Zone 8.6-0, Turbine Building;

1R06 Flood Protection Measures
BAR 0-38-A14, Turbine Building Fire/Oil Sump Flood Level, Revision 4;
1 BFR-Z.2, respond to Containment Flooding Unit 1, Revision 101;
2 BFR-Z.2, Respond to Containment Flooding Unit 2, Revision 101;
BHP 4200-81, Calibration of Magnetrol Flood Level Switch, Revision 4

1R07 Heat Sink Performance
WO 00588797, Inspection Heat Exchanger 2SX02K per Generic Letter 89-13, October 6, 2005;
IR 381461, The end bells of Heat Exchanger 2SX02K were found with significant deposits of mud and silt;
EC 357755, Past Operability Evaluation for Heat Exchanger 2SX02K;
IR 381941, The end bells and cover plates for Heat Exchanger 2SX02K had surface imperfections after being sand blasted;
0BOA ENV-1; Adverse Weather Conditions Unit 0; Revision 102
0BOA-ENV-2; Rock River Abnormal Water Level Unit 0; Revision 100
0BOA ENV-4; Earthquake Unit 0; Revision 100
0BOA PRI-7; Lost of Ultimate Heat Sink Unit 0; Revision 0
0BOL 7.9; LCOAR Ultimate Heat Sink (UHS) Tech Spec LCO # 3.7.9; Revision 7
1BOA ENV-1; Adverse Weather Conditions Unit 1; Revision 100
1BVSR SX-4; Unit 1 Essential Service Water Flow Verification; Revision 3
1BVSR XII-12; Ultrasonic Thickness Examinations of Selected Essential Service Water Components; Revision 3
2BOA Env-1; Adverse Weather Conditions Unit 2; Revision 100
BAP-560-3; Byron Cooling Water Chemistry Monitoring Program Description CW, WS, SX; Revision 7
BOP SX-T2; SX Tower Operation Guidelines; Revision 12
BRW-95-218; Evaluation of Essential Service Water Pump Operation with Degraded Lube Oil Coolers; Revision 0
BVP 200-19A1; Erosion/Corrosion Program; Revision 11
BVP 800-30; Service Water System (Essential Service Water) Fouling Monitoring Program; Revision 8
BVP 800-30; Attachment D GL 89-13 HX Inspection Cover Sheet Inspection Results for 1A Sx Pump Room Cubicle Cooler; dated March 10, 2000
BVP 800-30; Attachment D GL 89-13 HX Inspection Cover Sheet Inspection Results for 1B Sx Pump Room Cubicle Cooler; dated April 3, 2000
CR 145070; 1A DG JW HX Corrosion; dated February 2, 2003
CR 154998; Potential Adverse Impact on Configuration Control; dated April 4, 2003
CR 157568; 1B DG JW Deficiencies; dated May 7, 2003
CR 168022; Incorrect Use of Grace Period for GL 89-13 HX Inspection Frequency; dated July 17, 2003

CR 181006; Byron Station Review of OE 17031; dated October 15, 2003
CR 211766; Failed PMT on 2B DG Jacket Water Lower Cooler; dated March 30, 2004
CR 255966; U0 CC HX GL 89-13 Inspection Past Critical Date; dated August 23, 2004
CR 282088; Inspection Date of 1DG01KB HX Too Close to Critical Due Date; dated December 13, 2004
CR 291416; Filling and Venting Issues; dated January 17, 2005
CR 311626; As-Found Tube Blockage Accept Criter Not Met for 1AF01AB HX; dated March 11, 2005
CR 335594; As-Found Tube Blockage In Excess of Limit in Calc BYR04-005; dated May 16, 2005
CR 336162; 1A DG JW Cooler Tube Cleaning Issues; dated May 18, 2005
CR 353128; Deficiencies Identified During Heat Sink Performance FASA; dated July 14, 2005
CR 389412; NOS ID - IR Review Not Per FASA Plan Evaluation Criteria; dated October 24, 2004
CR 393026; EC 350427 Not Completed in Time; dated November 1, 2005
CR 394756; Results of Sr Mgr Challenge Mtg for Heat Sink Inspection; dated November 4, 2005
CR 399041; 2A SX Pp Oil HX Fails As-Found GL 89-13 Tube Blockage Ac; dated November 15, 2005
CR 399996; Time to Revisit Silting Issues at Byron; dated November 17, 2005
CR 428230; 1SX011 Valve Failed to Electrically Stroke Closed; dated November 28, 2005
CR 428265; 1SX136 Did Not Stroke Full Open When Requested; dated November 29, 2005
CR 428276; 1B SX Pp Oil HX Fails As-Found GL 89-13 Tube Blockage Ac; dated November 29, 2005
CY-AA-120-4110; Raw Water Chemistry Strategic Plan; Revision 0
Drawing E6000-3001; Cubicle Cooler; Revision E
EC 336446; Cubical Cooler Tube Plugging; dated October 3, 2002
EC 339308; Develop Tube Plugging Criteria for GL 89-13 Heat Exchanger Work with Harlan Kats to Determine Scope of HX in the Program; dated December 9, 2002
EC 344005; SX Pump Lube Oil Cooler Allowable Tube Blockage; Revision 0
EC 351458; Provide Justification for Extending GL 89-13 Inspection of 0CC01A Past Its Critical Due Date of 9/22/2004; Revision 0
EC 355492; Justification for Inspection Frequencies; Revision 0
EC 357755; Past Operability Evaluation for 2B AF Pump Right Angle Gear Lube Oil Cooler - 2SX02K; dated November 3, 2005
ER-AA-340; GL 89-13 Program Implementing Procedure; Revision 2
ER-AA-340-1001; GL 89-13 Program Implementation Instructional Guide; Revision 4
ER-AA-340-1002; Service Water Heat Exchanger and Component Inspection Guide; Revision 2
FASA AT 278787-04; Focused Area Self-Assessment Heat Sink Performance; dated November 7, 2005
Heat Exchanger Specification Sheet Ametek Job No. N80-40361; Sx Pump Lube Oil Cooler; dated February 25, 1980
Specification F/L-2900; Cubicle Coolers; dated July 18, 1983
UT Analysis Report: Sub-component 2SXH01-1; dated October 2, 1993

UT Analysis Report: Sub-component 2SXH01-1; dated February 12, 1995
UT Analysis Report: Sub-component 2SXH02-2; dated October 1, 1993
UT Analysis Report: Sub-component 2SXH02-2; dated February 14, 1995
UT Analysis Report: Sub-component 2SXH03; dated October 1, 1993
UT Analysis Report: Sub-component 2SXH03; dated February 14, 1995
UT Analysis Report: Sub-component 2SXL06; dated February 12, 1995
UT Analysis Report: Sub-component 2SXL06; dated August 29, 1996
VA-100; ESF Cubicle Energy Calculation; Revision 6
WO 584007; 2DG01KB - HX Inspection per GL 89-13
WO 604156; 2DG01KA - HX Inspection per GL 89-13; dated June 30, 2004
WO 661419; 1SX01AB - HX Inspection per GL 89-13; dated January 18, 2005
WO710086; 1DG01KA - HX Inspection per GL 89-13; dated May 9, 2005
WO 99157835; Perform SED Thermal Surveillance per BVP 800-30; dated November 8, 2001
WO 99157896; 2DG01KA - HX Inspection per GL 89-13; dated January 15, 2002
WO 99230765; 1VA01SA - HX Inspection Per Generic Letter 89-13; dated July 21, 2003

CR Generated From Inspection:
CR 428932; 0DO088 Apparently Leaking; dated November 30, 2005

1R08 Inservice Inspection Activities

Corrective Action Program Documents
AR 00212270, 2A SG Waterbox Foreign Objects; March 31, 2004;
AR 00212575, Foreign Objects Identified in 2D SG Preheater; April 1, 2004;
AR 00218465, Error in EPRI Report Leads to Low SG In-Situ Test; May 3, 2004;
AR 00232331, OE 18620 Bottom Head Visual - Lack of Coverage; June 29, 2005;
AR 00233562, Harris SG Tube Leak from Loose Parts; July 2, 2005;
AR 00292042, Ultrasonic Examination Reveals Thin Areas in FP Pipe, January 19, 2005;
AR 00297866, Required QV Hold Point Not Performed; February 1, 2005;
AR 00305116, U2 Steam Generator Secondary Side Cover ASME Code Issue, February 24, 2005;
AR 00354493, U2 SG Tube Not Expanded; July 19, 2005;
AR 00377135, TRM Appendix I Table Does Not List Latest Revision of WCAP-14976, September 23, 2005;
AR 00377795, Body to Bonnet Leakage 2RC8045D, September 25, 2005;
AR 00504902, Unit 2 ASME Section XI Pressure Test, April 8, 2004;
CR 276428, Ultrasonic Thickness Below Nominal Wall, November 24, 2004;
CR 313173, B1R13 LL 3/15/05 NRC ISI Audit Team Debrief Comments, March 15, 2005;
IR- 331095, Failure to Identify Thru-Wall FP Leak with an IR/WR, May 2, 2005

Corrective Action Program Documents as a Result of NRC Inspection
AR 00379823,Procedure ER-AP-335-1012 Needs Enhancement, September 29, 2005;
AR 00379827, Overly Conservative Use of Recordable Indication, September 29, 2005;
AR 00380389, Inadequate VT-2 Performed for EC 333251 Letdown Booster Pump, September 30, 2005;

AR 00380444, Failure to Evaluate Past Operability, September 30, 2005;
AR 00380254, Potential Historical Missed TRM TLCO 3.4.F Entry, September 30, 2005;
IR-00380472, Improper Penetrameter Placement During Radiographic Test, September 30, 2005;

Corrective Action Program Documents With Engineering Evaluations for Boric Acid Leakage
Evaluation No. 2004-315 for Component 2CV128, Minor Packing Leak; October 28, 2004;
Evaluation No. 2004-466 for Component 2RH029A, Valve Cap found Leaking at ½ Drop per Second, November 9, 2004;
Evaluation No. 2004-404 for Component 2SI121A, Boric Acid Leak at Base of Relief Valve, November 16, 2004;

Corrective Action Program Documents for Boric Acid Leakage
AR 00377795; Body-Bonnet Leakage from 2RC8045D; September 26, 2005.
AR 00377801; 2SI8956D Minor Dry Boron on B/B Flange; September 26, 2005.
AR 00379378; Boric Acid Packing Leak, Dry 2CV236; September 29, 2005.
AR 00379379; Boric Acid Leak at Body to Bonnet 2CV8160, Dry; September 29, 2005.
AR 00381103; Boric Acid Leakage at Check Valve Cap; October 3, 2005.

Documents Related to Pressure Boundary Welding
ASME Weld Data Record; 3"X16" weld-o-let; September 17, 2003.
ASME Weld Data Record; 2RH032AA-3; September 17, 2003.
ASME Weld Data Record; 2RH032AB-3; September 17, 2003.
Liquid Penetrant Examination Data Report 2003-244; FW-5; September 5, 2005.
Liquid Penetrant Examination Data Report 2003-287; FW-1; September 17, 2005.
Liquid Penetrant Examination Data Report 2003-289; FW-4&6; September 17, 2005.
Procedure ER-AA-335-005, Radiographic Examination, Revision 1.
PQR 1-51A; April 21, 2001.
PQR 4-51A; April 20, 2001.
PQR A-003; February 8, 2000.
PQR A-004; February 8, 2000.
Radiography Examination Report: 2003-216, welds W2 and W3 (and associated RT Film.); September 3, 2003.
VT-2 Visual Examination Record, 2RH8703 B/A; March 23, 2004.
VT-2 Visual Examination Record, 2RH8703 B/A; September 18, 2003.
Work Order 00366731; Install Line 2RH032AA-3" and 2RH032AB-3"; September 17, 2003.
WPS 8.8-GTSM; GTAW, SMAW; Revision 1.

Documents Associated with the Visual Examination of The Vessel Head
ER-AP-335-1012; Visual Examination of PWR Reactor Vessel Head Penetrations; Revision 1.

Documents Associated with Disposition of Relevant Indications
Data Sheet 2004-159; VT-3 examination of Support 2RC18001S, March 23, 2004.
Indication Data Sheet 2004-112, Ultrasonic Examination of Weld C30 on Line 2FW87CB-6"; March 30, 2004.

Documents Associated with ASME Code Nondestructive Examinations Observed
Ultrasonic Calibration Data Sheet B2R12-UT-011; 2FW03DD-16", FW C01, C02; September 27, 2005.
Ultrasonic Calibration Data Sheet B2R12-UT-012; 2RC28A-3", FW J03, J04, J05; September 27, 2005.
Ultrasonic Calibration Data Sheet B2R12-UT-013; 2FW87CA-6", FW C05, C06, C07, C08, C09; September 27, 2005.
Surface Examination Data Sheet 2MS07AD-28", E-2; September 27, 2005.

Documents Associated with Steam Generator Examinations
Amendment No. 144 to NPF-66; September 19, 2005.
EC 349439; SG Pressure Test Evaluation B2R11; Revision 0.
ER-MW-335-1009; Site Specific Performance Demonstration Program; Revision 1.
ETSS CBE-001-0905; Bobbin 40(IPS); September 26, 2005.
ETSS CBE-002-0905; Bobbin 24(IPS); September 26, 2005.
ETSS CBE-003-0905; Bobbin 24(IPS); September 26, 2005.
ETSS CBE-004-0905; 3Coil, +PT; September 26, 2005.
ETSS CBE-005-0905; 3Coil, +PT Dent; September 26, 2005.
ETSS CBE-006-0905; 3Coil, +PT MagBias; September 26, 2005.
ETSS CBE-007-0905; Low Row U-bend +PT; September 26, 2005.
ETSS CBE-008-0905; High Row U-bend +PT; September 26, 2005.
Letter BYRON 2005-0089; Byron Unit 2 Inspection Degradation Assessment and Condition Monitoring Checklist for B2R12; July 28, 2005.
Letter RS-04-159; Response to NRC Generic Letter 2004-01,"Requirements for Steam Generator Tube Inspection; October 29, 2004.
MRS 2.4.2 Gen-45; Standard In-Situ Pressure Test Using the Computerized Data Acquisition System; Revision 3.
Tube Plugging and Stabilization List; SG 2C; October 3, 2005.
Tube Plugging and Stabilization List; SG 2B; October 3, 2005.
Tube Plugging and Stabilization List; SG 2D; October 4, 2005.
Tube Plugging and Stabilization List; SG 2D; October 5, 2005.
Westinghouse Document DDM-96-009; Documentation of Appendix H Compliance and Equivalency, Pages 1-23; Revision 0.
Westinghouse Document SGS-02-013; Data Analysis Sizing Uncertainty of Volumetric Indications; March 18, 2002.
Westinghouse Memorandum; Use of Appendix H Qualified Techniques at Byron Unit 2 B2R12; August 16, 2005.

Other Documents
Form NIS-1; Manufacturers' Data Report for Nuclear Vessels, for A/B/C/D Steam Generators; February 5, 1980.
EC-354172; B1R13 End of Cycle 13 Effective Degradation Years In Accordance with NRC Order EA-03-009; Revision 1.

1R11 Licensed Operator Requalification Program (Quarterly)
1BOA-SEC-7; Auxiliary Feedwater Check Valve Leakage, Unit 1; Revision 102
1BOA-INST-2; Operation with a Failed Instrument Channel, Unit 2; Revision 103;
1BFR-S.1; Response to Nuclear Power Generation/ATWS, Unit 1; Revision 102;
1BEP-0; Reactor Trip or Safety Injection, Unit 1; Revision 107;
1BEP; SI Termination, Unit 1; Revision 106;

1R12 Maintenance Effectiveness
CR 381127, RCP Motor Slipped Off Hydraulic Lifting Devices, October 03, 2005;
CR 381133, Spare 2D RCP Motor Lifting Event, October 03, 2005;

1R13 Maintenance Risk Assessments and Emergent Work Control
Unit 1 Risk Configurations, Week of November 07, 2005;
Unit 1 Risk Configurations, Week of November 28, 2005, Revision 5;
Unit 1 and 2 Risk Configurations, Week of October 10, 2005, Revision 5;
Unit 2 Risk Configurations, Week of December 12, 2005;
CR 385348, 2FW009C Would not go Open, October 12, 2005;
CR 435841, On-line Risk Incorrect for 1CS019A Work, December 21, 2005;
CR 436179, NRC Concerns in the 1B EDG Room, December 21, 2005;
Byron’s Archival Operations Narrative Logs for October 12 and 13, 2005;
Byron’s Active Operations Narrative Logs, December 21, 2005;
Unit 1 and 2 Risk Configurations, Week of October 24, 2005, Revision 0;
WC-AA-101, Protected Equipment Process and Methodology, Revision 11;
WC-AA-101, On-line Work Control Process, Revision 11;
WC-AA-101-1004, On-line Maintenance for Limiting Condition for Operation of Systems or Components, Revision 3;
Policy No: 400-47, Byron Operating Department Policy Statement, Revision 8;
Shift Manager Daily Events, December 16, 2005;
Protected Equipment Log, December 21, 2005;
Unit 1 Risk Configurations, Week of December 19, 2005, Revision 2;
BAP 1100-3A3, Pre-evaluated Plant Barrier Matrix, Revision 17;

1R15 Operability Evaluations
CR 393772, 1B Diesel Generator Undervoltage Relay Failed Surveillance Criteria, November 2, 2005;
1BOSR 8.1.2-2, Unit One 1B Diesel Generator Operability Surveillance; Revision 19;
1BOSR 8.1.14-2, Unit One 1B Diesel Generator 24 Hour Endurance Run and Hot Restart Test, 18 Month; Revision 5;
License Event Report 89-001-01, Inadvertent Safety Injection During Generator Operability Surveillance Due to Procedural Inadequacies, August 8, 1989;
Report 05-029; IST Valve Evaluation for 2FW009C; October 14, 2005;
CR 388199; 2FW009C Would Not Open; October 20, 2005;
CR 385902; 2FW009C Failed Stroke Time Test; October 14, 2005;
CR 385348; Apparent Cause Report for 2FW009C Failure to Open Following B2R12; November 29, 2005;
Byron Station Logs for November 2, 2005;
WO 854993; 1B Diesel Generator Operability Monthly Surveillance
WO 697610; 1B Diesel Generator 24 Hour Endurance Run and Hot Restart Surveillance

1R16 Operator Workarounds
Adverse Condition Monitoring and Contingency Plan, 1D MSIV High Pressure Alarm, May 20, 2005;
Issue Resolution Documentation, 1D MSIV High Pressure Alarm, SER 2005-13, Revision 1
CR 320649, High Pressure on 1MS001D Hydraulic System and Standby Accumulator, April 04, 2005

1R17 Permanent Plant Modifications (Annual)
LS-AA-125-1001, Root Cause Report - Unit 2 Reactor Trip, Revision 5;
UFSAR Section 15.6.3.2, Steam Generator Tube Rupture, Revision 10;
CR 397646, Discrepancies Were Identified with the Unit 1 DEH Modification Tests, November 11, 2005;
CR 399021, Issue Identified with ½ BOA SEC-1 Regarding Turbine Runback, November 15, 2005;
Daily Orders, DEHC Update, November 15, 2005;
50.59 Review Coversheet, DEH Replacement, Revision 1;
SPP 05-003 Section 1, Moisture Reheat Separator (MSR) Modification Test, Revision 0

1R19 Post Maintenance Testing
CR 392142, Computer Point #P2302 is Failed to 51#, October 30, 2005;
CR 43607, 1A DG Large Swings in VARS During Monthly Surveillance
WO 610849, OP PMT - Cycle Breaker and Stroke 1SX033, December 15, 2005;
WO 676325, Limitorque Valve OPR Diagnostic test for 2B Containment Recirculation Sump Outlet Isolation Valve, October 4, 2005;
WO 719874, VT-2 Examination of Discharge Head Connection,2B CV Pump, October 21, 2005;
WO 862100, Computer Point #P2302 is Failed to 51#, October 30, 2005;
Issue 397232, B2R12 LL - Review and Evaluation of MOV Test Data, November 10, 2005;
2BOSR 0.1-1,2,3, Unit Two Mode 1, 2, 3 Tech Spec Data Sheet Reactor Trip System and ESFAS, October 30 and 31, 2005;
WO 697610, 1B DG 24 hour Endurance Run and Hot Restart Surveillance, November 1, 2005;
1BOSR 8.1.14-2, Unit One 1B Diesel Generator 24 Hour Endurance Run and Hot Restart Test, 18 Month, Revision 5;
1BOSR 8.1.2-2, Unit One 1B Diesel Generator Operability Surveillance, Revision 19;

1R20 Refueling and Outage Activities
Unit Two Operations Narrative Logs, September 25 - October 13, 2005;
B2R12 Outage Control Center Turnover, September 26 - October 11, 2005;
Shutdown Safety Equipment Status Checklist, various dates;

1R22 Surveillance Testing
IST-BYR-BDOC-V-25; Inservice Testing bases Document, February 21, 2005
2BOSR 0.5-2.SI.2-2.2; Unit Two 2SI18802B, 2SI18809B, 2SI18811B and 2SI18923B Stroke Test and Position Indication Test, Revision 7

2BVSR 5.c.2-1; Unit Two Flow Balance of the Charging/Safety Injection System To The Cold Legs (CM 7.6.5), Revision 1
WO 00751528; CV Pump ECCS Flow Balance Test After System Alteration, September 16, 2005
EC 357553; Flo-Series Evaluation of 2B CV Pump During B2R12, Revision 000
CR 425626, 2RF008 Calibration Procedure Enhancement Needed, November 18, 2005;
WO 686521, Perform Calibration of 2FT0RF008 Containment Floor Drain Leak Detector Flow Transmitter, December 13, 2005;
BAP 400-17, Partial Procedure Record; Revision 2
BISR 4.15.3-200, Surveillance Calibration of Containment Floor/Equipment Drain and Reactor Cavity Leak Detection Loop, Revision 4;

1R23 Temporary Modification
Engineering Change 353724, Removal of Tachometer Pickup Protective Guard from the Unit 1 B Train Diesel Generator

1EP4 Emergency Action Level and Emergency Plan Changes
Braidwood Station Emergency Plan; Revisions 15 and 16

1EP6 EP Drill Evaluation
Byron 2005 Fourth Quarter Security PI Drill Scenario Information
Fourth Quarter EP/LLEA Drill Findings and Observation Report, December 20, 2005

2OS1 Access Control to Radiologically Significant Areas; and

2OS2 ALARA Planning And Controls
NF-AA-390; Spent Fuel Pool Material Control; Revision 1
B2R12 Cobalt Release Data
CR327893; Request PM ID Frequency Change to Semi-Annual Observation; dated April 22, 2005
AR341834; Elevated Radiation Background Level at AB 401' Exit; dated June 7, 2005
AR272663; Radiation Protection Post Outage ALARA Assessment; dated November 11, 2004
IR316023; Alloy 600 Westinghouse RP/ALARA Lessons Learned; dated March 22, 2005
CR315005; B1R13 LL OCC Intervention Causing RWP Violations; dated March 19, 2005
CR342233; RXS Technicians on Wrong RWP; dated June 8, 2005
AR256482-02; Apparent Cause Evaluation: Electronic Dosimeter Not Responding to Neutron Radiation; dated December 23, 2004
AR318930; Common Cause Analysis: Rad Worker Practices; dated May 13, 2005
Monthly Data Elements for NRC Occupational Exposure Control Effectiveness
Individual Dose Report (TE011); dated October 7, 2005
Environmental Lower Limits of Detection
ATI 279546-04; ALARA Readiness Check-In; dated August 22, 2005
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B2R12 ALARA Index
RWP 10005473; S/G Eddy Current and Tube Repairs; Revision 1
RWP 10005463; Lead Shielding - Install, Maintain, and Remove; Revision 1

2PS3 Radiological Environmental Monitoring and Radioactive Material Control Programs

2004 Annual Radioactive Effluent Release Report and Addendum to 2003 Annual Radioactive Effluent Release Report; dated April 30, 2005
2003 Annual Radioactive Effluent Release Report; dated April 30, 2004
2003 Annual Radiological Environmental Operating Report; dated May 15, 2004
2004 Annual Radiological Environmental Operating Report and Current Revision of The Byron Station Off-site Dose Calculation Manual (ODCM); dated May 15, 2005
AR 00324066; U1 and U2 Exceed ODCM Projection for Organ Dose in March; dated April 13, 2005
AR 00325266; Reporting Errors in The 2003 Annual Radiological Environmental Report; dated April 15,2005
AR 00165050; Issues Identified During REMP FASA; dated June 26, 2003
AR 00319730; ODCM LLD's Are Incorrect/Iodine Sampling Varies from NUREG; dated March 31, 2005
AR 00178862; QATR Appendix A R/70 Versus RG 4.15 Discrepancies; dated October 2, 2003
AR 00179892; NOS Identified Met Tower Contractor Not Audited; dated October 8, 2003
CY-AA-170-1000; Radiological Environmental Monitoring Program and Meteorological Program Implementation; Revision 0
RP-BY-503; Unconditional Release Survey Method; Revision 0
EIML-SPM-1; [REMP] Sampling Procedures Manual - Environmental Incorporated Midwest Laboratory; Revision 9 (June 6, 2005)
Exelon Audit No. NOSA-BYR-03-08; REMP, ODCM, Non-Radiological Monitoring /NPDES Audit Report; dated November 11, 2003
Nuclear Utilities Procurement Issues Committee (NUPIC) Joint Quality Assurance Program Audit Report - Environmental Incorporated Midwest Laboratory; NUPIC Audit Number 18558; dated June 3, 2003
State of New York, Department of Health Assessment Report for Teledyne Brown Engineering - Environmental Service; dated September 7, 2004
Toxco Materials Management Center's Quality Assurance Audit of Teledyne Brown Engineering; Vendor Audit A05-01; dated June 24, 2005
Focus Area Self-Assessment (Check-In) Report: Radiological Environmental Monitoring Program; dated February 15 - 23, 2005
Monthly Report on the Meteorological Monitoring Program at the Byron Nuclear Station; dated January 2005 through July 2005
REMP-6; Pump Maintenance Data; dated January 2004 through March 2005
REMP-3; Pump Field Check Data; dated May 2004 through September, 2005
REMP-9-1; Land Use Census - Milch Animals; dated August 9, 2005
REMP-9-2; Land Use Census - Nearest Livestock; dated August 13 an 14, 2005
REMP-9-3; Land Use Census - Nearest Residence; dated August 13, 2005

4OA2 Identification and Resolution of Problems

Common Cause Analysis 351213, NRC Identified Human Performance Cross-cutting Issue for Byron Station and Station Event Free Clock Resets, dated December 8, 2005;
Focused Area Self-Assessment 350127, Byron Station Human Performance and Technical Human Performance, dated August 20, 2005;

Byron Site Policy Memo 200.26; Human Performance Task Force; dated November 3, 2005;
Byron Site Policy Memo 200.51, Guidance for Integrated Performance Management System; dated November 2, 2005
100 day plan, dated December 13, 2005;
Departmental Human Performance Improvement Plan for Electrical Maintenance, date fourth Quarter 2005;
Operations Trend Improvement Initiatives; Time Period; 2005 second and third Quarter;
Chemistry Trend Improvement Initiatives; Time Period; 2005 second and third Quarter;
Maintenance Rule - Performance Criteria, Ultimate Heat Sink Temperature Control;
CR 111838, Void Discovered in SX Cooling Tower Concrete During Repairs, June 13, 2003
CR 227277, Void Identified in SX Cooling Tower Fill Support Beam, June 09, 2004;
AR 227277, Extent of Condition review, October 15, 2004;
CR 357066, 0A SX Cooling Tower Concrete Degradation, July 27, 2005;
CR 432671, Some Fill Damage in Unit 1 NDCT, December 10, 2005
CR 437338, Unit 1 W Outfall Screen Coming Loose From Concrete, December 29, 2005;
Issue 356940, Expanded Scope for Grout Repairs on SXCT D Cell, July 26, 2005;
WR 970114175 01, Perform Minor Concrete Repairs to “B” Cell Structure;
WR 970129710 01, Perform Minor Concrete Repairs to “F” Cell Structure
WR 980019429 01, Perform Concrete Repairs to “A” Cell Structure;
WR 980033192 01, Perform Minor Concrete Repairs to “C” Cell Structure;
WR 980033713 01, Perform Minor Concrete Repairs to “G” Cell Structure;
WR 980033718 01, Perform Minor Concrete Repairs to “H” Cell Structure;
WR 980011671 01, Perform Concrete Repairs to “B” Cell Structure;
WR 980033714 01, Perform Minor Concrete Repairs to “D” Cell Structure

4OA3 <u>Event Followup</u>

LER 2005-005-00, Both Trains of the Ultimate Hear Sink Water Makeup Trains Exceeded TS Required Action Completion Time Due to Contaminated fuel Oil Resulting From Inadequate Tank cleaning Procedure;
October 14, 2005
Unit 2 Reactor Trip Lessons Learned, Log No 05-033, Revision 0;
Prompt Investigation Report, Unit 2 Reactor Trip on Loss of 2A Condensate;
CR 387581, Unit 2 Reactor Trip on Loss of CD/CB PP2A, October 19, 2005;
CR 387431, Unit 2 NRC 88-08 Temperature Monitoring Data Evaluation, October 18, 2005;
CR 387579, 2FW009D FWI Monitor Light Did Not Illuminate as Required, October 19, 2005;
CR 387582, 2A CD/CB Trip, October 19, 2005;
CR 387583, Unit 2 DEHC Panel Shows Dual Indication for #4 Governor Valve, October 19, 2005;
CR 387590, 2E MPT Combustible Gas Alarm During Unit 2 Reactor Trip, October 19, 2005;
CR 387603, 2FW520 Did Not Full Close Following Unit 2 Reactor Trip, October 19, 2005;
CR 387698, Missing DEHC Page 10 from Controller, October 19, 2005

OP-AA-108-114, Post Transient Review, October 19, 2005;
PORC 05-038 & 05-039, Byron Plant Operating Review Committee Minutes, October 19, 2005;
Startup of Byron Unit 2 Following Runback Failure of DEH System Drop 3/53, October 19, 2005;

4OA5 Pressurizer Penetration Nozzles and Steam Space Piping Connections in U. S. Pressurized Water Reactors (TI 2515/160)

Exelon Letter; Initial Response to NRC Bulletin 2004-01, Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors; dated July 27, 2004.
Work Order 00745675; Examine DM Welds Pressurizer Top Nozzles; August 24, 2005.
Level III VT-2 Certification Record; Robert G McBride; February 21, 2005.
TQ-AA-122; Qualification and Certification of Nondestructive(NDE) Personnel; Revision 1.
Visual Examination Report, VT-2, September 28, 2005.
ER-AA-335-015; VT-2 Visual Examination; Revision 4.
Drawing EDSK379550/B; Spray Nozzle; Revision B.
Drawing EDSK379445/B, Safety Relief Nozzle; Revision B.
ER-AP-331-1001; Boric Acid Corrosion Control (BACC) Inspection Locations, Implementation and Inspection Guidelines; Revision 1.
ER-AP-331-1002; Boric Acid Corrosion Control Program Identification, Assessment, and Evaluation; Revision 2.

LIST OF ACRONYMS USED

ACE	Apparent Cause Evaluation
ADAMS	Agency wide Documents Access and Management System
AFW	Auxiliary Feedwater
AR	Action Request
ASME	American Society of Mechanical Engineers
BACC	Boric Acid Corrosion Control
CFR	Code of Federal Regulations
CR	Condition Report
DD	Diesel Driven
DRP	Division of Reactor Projects; Region RIII
EAL	Emergency Action Level
EDY	Effective Degradation Years
EH	Turbo Electro-Hydraulic Control
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
ET	Eddy Current
GL	Generic Letter
IMC	Inspection Manual Chapter
IR	Inspection Report
ISI	Inservice Inspection
LCOAR	Limiting Condition for Operation Action Requirement
LER	Licensee Event Report
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NDE	Nondestructive Examination
No.	Number
NPP	Nuclear Power Plants
NRC	United States Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
ODCM	Offsite Dose Calculation Manual
OSP	Offsite Power
PARS	Public Availability Records
PI	Performance Indicator
PSIG	Pounds Per Square Inch Gage
PWR	Pressurized Water Reactor
RCS	Reactor Coolant System
REMP	Radiological Environmental Monitoring Program
RETS	Radiological Environmental Technical Specifications
RP	Radiation Protection
RWST	Refueling Water Storage Tank
SBO	Station Blackout
SDP	Significance Determination Process
SG	Steam Generator
SSC	Structures, Systems for Components
SSPS	Solid State Protection System

SX	Essential Service Water
TI	Temporary Inspection
TR	Technical Requirement
TRM	Technical Requirements Manual
TS	Technical Specification
TSO	Transmission System Operator
U	Unit
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Examination
VCT	Volume Control Tank
WO	Work Order
WR	Work Request
WS	Non-Essential Service Water