July 25, 2003

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

SUBJECT: BYRON STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000454/2003003;
05000455/2003003

Dear Mr. Skolds:

On June 30, 2003, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Byron Station, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on June 26, 2003, with Mr. R. Lopriore and other members of your staff.

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

Three findings of very low safety significance (Green) were identified in the report. Two of the three findings were determined to involve violations of NRC requirements. However, because of the very low significance of these two findings, and because they were entered into your corrective action program, the NRC is treating the issues as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of the Non-Cited Violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U. S. Nuclear Regulatory Commission - Region III, 801 Warrenville Road, Lisle, IL 60532-4351; the Director, Office of Enforcement, U. S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector office at the Byron facility.

Since the terrorist attacks on September 11, 2001, NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen the licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction (TI) 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect the licensee's implementation of the interim compensatory measures required by the Orders. Phase 1 of TI 2515/148 was completed at all commercial power nuclear power plants during calender year 2002 and the remaining inspection activities for the Byron Station were completed in May 2003. The NRC will continue to monitor overall safeguards and security controls at the Byron Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Ann Marie Stone, Chief
Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000454/2003003 ;
05000455/2003003
Attachment: Supplemental Information

cc w/encl: Site Vice President - Byron
Byron Station Plant Manager
Regulatory Assurance Manager - Byron
Chief Operating Officer
Senior Vice President - Nuclear Services
Senior Vice President - Mid-West Regional
Operating Group
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing - Mid-West Regional Operating Group
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REGION III

Docket Nos:	50-454; 50-455
License Nos:	NPF-37; NPF-66
Report Nos:	05000454/2003003; 05000455/2003003
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	4450 N. German Church Road Byron, IL 61010
Dates:	April 1, 2003 through June 30, 2003
Inspectors:	R. Skokowski, Senior Resident Inspector P. Snyder, Resident Inspector R. Alexander, Radiation Specialist S. Burgess, Senior Reactor Analyst J. Creed, Safeguards Program Manager T. Madeda, Physical Security Inspector N. Valos, Operator Licensing Examiner C. Thompson, Illinois Department of Nuclear Safety
Approved by:	Ann Marie Stone, Chief Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000454/2003003, 05000455/2003003; on 04/01/03-06/30/03; Byron Station; Units 1 & 2. Maintenance Effectiveness, Maintenance Risk & Emergent Work Control, and Problem Identification and Resolution.

This report covers a 3-month period of baseline resident inspection and an announced baseline inspection on radiation protection. The inspections were conducted by a regional radiation specialist inspector, regional physical security inspectors and the resident inspectors. Three Green findings, two of which were violations of NRC requirements, were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

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

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance was identified through a self-revealing event when the licensee failed to adequately specify, in procurement documentation, the testing methods for determining total water concentration for oil samples taken from the 2B emergency diesel generator mechanical governor. The subsequent sample results incorrectly indicated a higher than actual water concentration in the governor oil, and led the licensee to take actions that resulted unnecessary unavailability time of the emergency diesel generator. The failure to adequately specify the appropriate test methodology was related to the cross-cutting area of human performance. Following identification of this issue the licensee changed the sample requirements so that the appropriate test method is now specified for diesel generator governor oil samples.

  This finding was more than minor because it impacted the mitigating system cornerstone stone objective causing the availability of a system that responds to initiating events to prevent undesirable consequence. This finding was of very low safety significance because there was no design deficiency, no actual loss of safety function, no single train loss of safety function for greater than the Technical Specification allowed outage time, and no risk due to external events. This issue was a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion IV, "Procurement Document Control." (Section 1R12)

- Green. The inspectors identified a finding of very low safety significance regarding the licensee's failure to assess the increase in risk in accordance with 10 CFR 50.65(a)(4) that resulted following the isolation of a pressurizer power operated relief valve (PORV) by closing its associated block valve. The primary cause of this finding was related to the cross-cutting area of human performance. Despite the availability of a computer software tool that would have indicated additional evaluation was required, the risk evaluation was not completed. Following identification of this issue, the licensee performed a risk review and determined that the plant was not in the condition of core life when immediate actuation of the pressurizer PORVs are required; therefore, isolation of the pressurizer PORV did not result in an increased online risk.

This finding was more than minor because it affected the human performance attribute of the mitigating systems cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. This finding was of very low safety significance because there was no design deficiency, no actual loss of safety function, no single train loss of safety function for greater than the Technical Specification allowed outage time, and no risk due to external events. The inspectors determined this to be a Non-Cited Violation of 10 CFR 50.65 (a) (4). (Section 1R13)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance was identified through a self-revealing event when supervisors and workers did not uphold the foreign material exclusion standards during previous maintenance activities which resulted in a steam generator tube leak. The finding was not considered a violation of regulatory requirements. The failure to adequately control foreign material was related to the cross-cutting area of human performance.

  This finding was more than minor because it involved the human performance attribute that affected the reactor coolant system portion of the barrier integrity cornerstone objective. This finding was of very low safety significance because (1) the plant did not operate at-power with one or more tubes that should have been but were not repaired or plugged based on previous tube inspection results; (2) the tubes in question were found to meet required performance criterion for pressure, as demonstrated by the in-situ testing; and (3) the leakage rate of the tubes was below the 150 gallons per day Technical Specification criteria and below the calculated "accident leakage" rate. No violations of NRC requirements occurred. (Section 4OA2.2)

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

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

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power throughout the inspection period except on May 19, 2003, when power was reduced to about 77 percent for turbine throttle valve/governor valve testing.

Unit 2 operated at or near full power throughout the inspection period except on May 18, 2003 when power was reduced to about 25 percent to add oil to two reactor coolant pumps. Power was also reduced on Unit 2 three times for load following: on May 27, 2003 to about 75 percent; on June 22, 2003 to about 70 percent; and on June 27, 2003 to about 75 percent.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

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

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

On June 5, 2003, the inspectors performed a walkdown of the plant perimeter and river screen house. The purpose of the walkdown was to assess the adequacy of the protection of plant equipment and the plant's offsite power supply from possible airborne missile hazards caused by high winds.

Additionally, the inspectors reviewed the licensee's response to severe thunderstorm warnings on June 25, 2003.

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

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdowns

a. Inspection Scope

The inspectors performed four partial walkdowns of accessible portions of trains of risk-significant mitigating systems equipment during times when the trains were of increased importance due to the redundant trains or other related equipment being unavailable. The inspectors utilized the valve and electric breaker checklists listed in the Attachment at the end of this report and applicable system drawings to verify that the components were properly positioned and that support systems were lined up as needed. The inspectors also examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors used the information in the appropriate sections of the Updated Final Safety Analysis Report (UFSAR) to determine the functional requirements of the systems.

The inspectors verified the alignment of the following trains:

- Unit 2 train A of the residual heat removal system while train B was out-of-service for maintenance on April 15, 2003;
- Unit 1 and Unit 2 4.1kV and 6.9 kV buses while the Unit 2 system auxiliary transformers were out-of-service for maintenance on April 21, 2003;
- Unit 1 circulating water system while the Unit 1 D circulating water box was out-of-service on May 2, 2003; and
- Unit 1 train A auxiliary feedwater system while train B was out of service on May 15, 2003.

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

On May 8, 2003, the inspectors performed a complete system alignment inspection of the auxiliary power (AP) 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:

- a review of plant procedures (including selected abnormal and emergency procedures), drawings, and the UFSAR to identify proper system alignment;
- a review of operator work arounds to determine applicability to the auxiliary power system;
- a review of outstanding work requests on the system;
- a review of the auxiliary power system health evaluation; and
- an electrical walkdown of the system to verify proper alignment, component accessibility, availability, and current condition.

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

The inspectors examined the plant areas listed below to observe conditions related to fire protection:

- Main control room (Zone 2.1-0) on April 9, 2003;
- Unit 2 turbine building elevation 426 (Zone 8.5-2) on April 17, 2003;
- Circulating water pumphouse (Zone 18.12-0) on May 2, 2003;

- 2A and 2B reactor coolant pump lube oil collection systems during an expected lube oil leak on the 2A reactor coolant pump on May 18, 2003;
- Unit 1 upper cable spreading room (Zones 3.3A-1 and 3.3.B-1) on May 20, 2003;
- Unit 1 and Unit 2 auxiliary building 383 foot elevation (zone 11.4-0) on June 3, 2003; and
- Unit 1A and D main steamline isolation valve room during hot work activities on June 3, 2003

b. Findings

No findings of significance were identified.

.2 Drill Observation

a. Inspection Scope

The inspectors assessed fire brigade performance and the drill evaluator's critique during a fire brigade drill conducted on May 4, 2003. The drill simulated an oil fire in the Unit 1 turbine clean and dirty oil storage tank room. 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; and implementation of pre-fire plan strategies. The inspectors evaluated the fire brigade performance using the licensee's established fire drill performance procedure criteria. The inspectors verified that minor issues identified during the inspection were entered into the licensee's corrective action program. The documents listed at the end of this report were also used by the inspectors to evaluate this area.

The inspectors also reviewed selected issues documented in CRs, to determine if they had been properly addressed in the licensee's corrective actions program.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

During the week of April 28, 2003, the inspectors evaluated the licensee's controls for mitigating external and internal flooding by completing a semi-annual and a annual sample. Specifically, the inspectors performed the following:

- Reviewed the licensee's design basis documents to identify the design basis for flood protection and to identify those areas susceptible to external or internal flooding;
- Reviewed the licensee's probabilistic risk assessment results for external and internal flooding;
- Reviewed selected maintenance records based on the assessment results;

- Reviewed selected abnormal operating procedures for identifying and mitigating flooding events;
- Reviewed selected maintenance records and surveillances for auxiliary building floor drains;
- Reviewed selected records documenting the evaluation of underground cables for submergence; and
- Inspected the watertight doors and flood seals.

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

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed selected issues documented in condition reports associated with heat sink performance to determine if they had been properly addressed in the licensee's corrective actions program. The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No new findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On May 19, 2003, the inspectors observed an operating crew during an "out-of-the-box" requalification examination on the simulator using Scenario "Number 03-03-1," Revision 0. The inspectors evaluated crew performance in the areas of:

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

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

- OP-AA-101-111, “Roles and Responsibilities of On-Shift Personnel,” Revision 0;
- OP-AA-103-102, “Watchstanding Practices,” Revision 1;
- OP-AA-103-103, “Operation of Plant Equipment,” Revision 0;
- OP-AA-103-104, “Reactivity Management Controls,” Revision 0; and
- OP-AA-104-101, “Communications,” Revision 0.

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

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

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated the licensee’s implementation of the maintenance rule, 10 CFR 50.65, as it pertained to identified performance problems with the following system:

- HD, feedwater heater drain tank level control.

During this inspection, the inspectors evaluated the licensee’s monitoring and trending of performance data for the past two years, verified that performance criteria were established commensurate with safety, and verified that equipment failures were appropriately evaluated in accordance with the maintenance rule. These aspects were evaluated using the maintenance rule scoping and report documents listed in the Attachment at the end of this report. For each system, structure, and component reviewed, the inspectors also reviewed the significant work orders and condition reports listed in the Attachment at the end of this report to verify that failures were properly identified, classified, and corrected, and that unavailable time had been properly calculated. The inspectors also visually inspected heater drain tank level controllers and interviewed system engineers and operations department personnel.

b. Findings

No findings of significance were identified for the sample inspected under the maintenance effectiveness inspection procedure. However, as discussed below, a finding related to maintenance effectiveness was identified during the review of the operability evaluation associated with Engineering Change Analysis 343232, “Evaluation of Governor Oil/Water Content in the Unit 2 Train B Emergency Diesel Generator.”

Introduction

A Green finding was identified through a self-revealing event when the licensee failed to adequately specify, in procurement documentation, the testing methods for determining total water concentration for oil samples taken from the 2B emergency diesel generator mechanical governor. The subsequent sample results incorrectly indicated a higher than actual water concentration in the governor oil. Based on this incorrect information, the licensee took actions to flush the governor oil. These actions were not necessary and resulted in additional unavailability time of the emergency diesel generator. This issue was determined to be of very low safety significance and was dispositioned as a Non-Cited Violation.

Description

On June 4, 2003, an operator noted that the level in the 2B emergency diesel generator mechanical governor oil sight glass was out-of-sight high. The operator informed the shift management of the condition, and the issue was entered into the licensee's corrective action program. The shift manager declared the 2B emergency diesel generator inoperable. Troubleshooting revealed that the mechanical governor oil cooler developed a leak and the cooling water was leaking into the governor oil. The licensee replaced the oil cooler and flushed the governor sump to remove excess water prior to filling the governor oil sump. The diesel was tested satisfactorily and the shift manager declared the diesel operable on June 5, 2003. Additionally, after completing the work on the diesel, the licensee took a sample of the mechanical governor oil to verify acceptable water content. The sample was provided to the vendor normally used by the licensee to analyze diesel oil samples.

The oil sample results indicated that the water content was higher than expected, and the water content was found to be in the alert range. The licensee then sent a sample from the oil container used to fill the governor and again, the sample results indicated that the water content in the container was also high and at concentration similar to the results obtained from the governor oil. The licensee determined that the diesel was operable and initiated plans to monitor oil level and flush the oil in the near future. (The inspectors reviewed the operability evaluation under Section 1R15 of this report.) Additionally, the licensee entered these issues into the corrective action program, quarantined the suspected oil container, and initiated an extent of condition evaluation to determine other possible locations where this oil could have been used.

The licensee sampled oil from a new container and the results provided by the vendor indicated acceptable water content. The licensee decided to take the 2B emergency diesel generator out of service to flush and replace the governor oil with oil from this new container. At 6:09 a.m. on June 11, the diesel was declared inoperable and at 2:06 p.m. on June 11, the replacement was complete and the diesel was returned to service. The licensee sampled the oil from the governor and again, was informed that the indicated water content again in the alert range. The licensee entered this issue into the corrective action program and started to question the adequacy of the vendor's analysis for sampling the governor oil.

The licensee determined that the oil analysis completed by the vendor, was inappropriate for the additives contained in the governor oils and that for oils with these additives, the analysis would routinely indicate a higher than actual total water content. Specifically, Purchase Requisition Number 368093, regarding Testing of Lubricants and Diesel Fuel specified the use on ASTM D1744, “Test Method for Water in Liquid Petroleum Products by Karl Fischer Reagent.” The test method described by this standard had known interferences for the additives in the oil used within the EDG mechanical governor. The licensee determined that the appropriate test was Test Procedure C as describe in ASTM D6304, “Standard Test Method for Determination of Water in Petroleum Products, Lubricating Oils, and Additives by Coulometric Karl Fischer Titration.” Subsequently, oil samples were provided to four laboratories and the sample results, utilizing appropriate methods, indicated that the water content in the governor and from both the new and quarantined barrels were acceptable.

Analysis

The inspectors determined that the failure to specify the appropriate oil sample analysis requirements resulted in the unnecessary unavailability of the 2B emergency diesel generator on June 11, 2003. This was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Disposition Screening,” issued on April 29, 2002. The inspectors determined that the finding was more than minor since it affected the mitigating system cornerstone stone objective regarding the availability of a system that responds to initiating events to prevent undesirable consequence. The inspectors determined that this deficiency affected the cross-cutting area of Human Performance since the procurement engineering personnel did not specify an appropriate test for oil samples.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” because the finding was associated with the operability, availability and reliability of a train of a mitigating system. For the Phase 1 screening, the inspectors answered “no” to all the questions in the Mitigating System column, because there was no design deficiency, no actual loss of safety function, no single train loss of safety function for greater than the Technical Specification (TS) allowed outage time, and no risk due to external events. Therefore, the finding was of very low safety significance (Green).

Enforcement

10 CFR 50, Appendix B, Criteria IV, “Procurement Document Control,” required, in part, that measures shall be established to assure regulatory requirements, design bases, and other requirements which are necessary to assure requirements which are necessary to assure adequate quality are suitably included or referenced in documents for procurement of services. Contrary to the above, on or before June 12, 2003, the licensee did not include the appropriate testing requirements for determining total water content for the emergency diesel generator mechanical governor oil samples were included in Purchase Requisition Number 368093. Because of the very low safety significance, this violation is being treated as a Non-Cited Violation consistent with Section VI.A of NRC Enforcement Policy (NCV 05000455/2003003 -01). The licensee

entered the problem into its corrective action system as Condition Report 163059, "Oil Program Questioning Attitude Identifies Testing Issue," dated June 12, 2003.

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, observed operator turnovers, observed plan-of-the-day meetings, and reviewed the documents listed in the Attachment at the end of this report to verify that the equipment configurations had been properly listed, that protected equipment had been identified and was being controlled where appropriate, and that significant aspects of plant risk were being communicated to the necessary personnel. The inspectors verified that the licensee controlled emergent work in accordance with Nuclear Station Procedure WC-AA-101, "On-Line Work Control Process," Revision 6.

The inspectors reviewed the following activities:

- Simultaneous planned work associated with the Unit 2 system auxiliary transformers 242-1 and 242-2 on April 21, 2003;
- Simultaneous planned work associated with the Unit 0 essential service water train B blowdown isolation valve 161 and the Unit 2H steam dump valve on April 15, 2003;
- Simultaneous planned work associated with the Unit 1 residual heat removal train A and the Unit 0 auxiliary building ventilation system train C on April 7, 2003;
- Simultaneous work associated with planned maintenance on the Unit 2 containment spray train A and emergent maintenance on the Unit 2 feedwater pump train A on April 28, 2003;
- Simultaneous work associated with planned maintenance on the Unit 1 emergency diesel generator and emergent maintenance on the Unit 1 diesel driven auxiliary feedwater pump on May 9, 2003; and
- Simultaneous work associated with planned maintenance on the Unit 1 circulating water pump train B auxiliary feedwater pump train B, containment spray pump train B, the Unit 0 essential service water cooling tower fan train G,

and the emergent Unit 0 VC chiller train B out of service during the week of May 12, 2003.

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

b. Findings

Introduction

The inspectors identified one finding of very low safety significance (Green). The licensee failed to assess the increase in risk in accordance with 10 CFR 50.65(a)(4) that resulted following the isolation of a pressurizer power operated relief valve (PORV) by closing its associated block valve. This issue was determined to be of very low safety significance and was dispositioned as a Non-Cited Violation.

Description

On December 9, 2002, the licensee identified an increasing temperature in the piping downstream of a pressurizer power operated relief valve (PORV) which indicated a steam leak past the valve seat. In accordance with the technical specification, the licensee closed the associated block valve. On December 14, 2002, the pressurizer PORV was unisolated by opening the valve since it appeared to operators that the temperature had stabilized. On December 17, 2002, the pressurizer PORV was again isolated for the same problem. At that time operator's logs documented that online risk remained green since the PORV was energized and able to be unisolated by operators.

On May 5, 2003, the inspectors learned that the recent closing of a pressurizer PORV at the Braidwood Station had led the Braidwood licensee there to raise online risk to the yellow level as designated by licensee procedures. The inspectors posed the question to the Byron site risk engineer as to why a similar determination had not been made at Byron Station following the isolation of the pressurizer PORV in December 2002. After discussion with the risk engineer, the inspectors determined that a proper risk evaluation had not been performed. During anticipated transient without scram (ATWS) scenarios at certain periods in core life, immediate pressure relief provided by the automatic operation of the pressurizer PORV is required to mitigate the accident scenario; therefore, at those times, manual action to unisolated the PORV block valve would be inadequate. At that time the risk engineer generated Condition Report 158362 to enter the inadequate risk evaluation into the licensee's corrective action program. A subsequent complete risk review determined that the plant was not in the condition of core life where immediate actuation of the pressurizer PORV was required; therefore, the isolation of the pressurizer PORV by closing its associated block valve did not result in an increased online risk.

Analysis

The inspectors determined that the failure to assess the risk associated with isolation of a pressurizer PORV by closing its associated block valve was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on April 29, 2002. The inspectors determined that the finding was more than minor because it affected the human performance attribute of the mitigating systems cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that the failure to ensure an adequate risk assessment was performed by the operations personnel also affected the Human Performance cross-cutting area because a computer software tool was available to assess the risk.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," because the finding was associated with the potential degradation of the pressurizer PORV to reliably act as a mitigating system for certain ATWS scenarios as discussed above. For the Phase 1 screening, the inspectors answered "no" to all five questions in the mitigating system cornerstone column because the finding did not represent an actual loss of function nor did it involve a potentially risk significant due to external events. Therefore, the finding was of very low safety significance (Green).

Enforcement

10 CFR 50.65(a)(4) requires, in part, that before performing maintenance activities (including but not limited to surveillances, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to the above, on December 9, 2002, the licensee failed to assess the risk associated with maintenance activities following the isolation of a pressurizer PORV, which was not available to respond automatically as required for ATWS scenarios at certain periods in core life. Because of the very low safety significance, this violation is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000454/2003003-02). The licensee entered this violation into its corrective action program as CR 00158362, dated May 5, 2003.

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

a. Inspection Scope

The inspectors observed control room operators during the following non-routine evolution:

- Unit 2 down power to 30 percent for a containment entry to add lube oil to the 2A and 2B reactor coolant pumps on May 18, 2003.

The inspectors evaluated crew performance in the areas of:

- clarity and formality of communications;
- prioritization, interpretation and verification of alarms;
- procedure use;
- control board manipulations;

- supervisor's command and control;
- management oversight; and
- group dynamics.

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

- OP-AA-101-111, "Roles and Responsibilities of On-Shift Personnel," Revision 0;
- OP-AA-103-102, "Watchstanding Practices," Revision 1;
- OP-AA-103-103, "Operation of Plant Equipment," Revision 0;
- OP-AA-103-104, "Reactivity Management Controls," Revision 0; and
- OP-AA-104-101, "Communications," Revision 0.

The documents listed in the Attachment at the end of this report were also used by the inspectors to evaluate this area.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors evaluated plant conditions, selected condition reports, 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 reviewed the following operability evaluations:

- Condition Report 154855, Unit 1 main steam isolation valve accumulators found out of tolerance;
- Operability Determination 03-002, incorrect hydraulic fluid found in the 1B Feedwater Isolation Valve accumulators;
- Engineering Change Analysis 343232, evaluation of governor oil/water content in the Unit 2 train B emergency diesel generator; and
- Operability Determination 03-003, operability of spurious valve actuation group valves in the emergency core cooling system.

The inspectors compared the operability and design criteria in the appropriate section of the TS and UFSAR to the licensee's evaluations to verify that the components or systems were operable. The inspectors determined whether compensatory measures, if needed, were taken, and determined whether the evaluations were consistent with the requirements of licensee's Procedure LS-AA-105, "Operability Determination Process," Revision 0. The inspectors also discussed the details of the evaluations with the shift managers and appropriate members of the licensee's engineering stf.

The documents listed in the Attachment at the end of this report were also used by the inspectors to evaluate this area.

b. Findings

No findings of significance were identified. However, during the review of the engineering change analysis associated with the governor oil/water content in the 2B emergency diesel generator, a finding associated with maintenance effectiveness was identified and is described in Section 1R12 of this report.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed the following condition report to determine if the condition reached the threshold for being considered an operator work-around or operator challenge:

- CR 160689, 1D second stage reheater drain tank emergency valve non-responsive.

The inspectors interviewed operating and engineering department personnel and reviewed the licensee's changes taken to address this condition. The documents reviewed during this inspection are listed in the Attachment to this report.

The inspectors also reviewed the licensee's quarterly review operator work-arounds to verify that the cumulative effects of operator work-arounds and operator challenges did not adversely impact the ability to operate the plant.

The inspectors also reviewed selected issues documented in condition reports, to determine if they had been properly addressed in the licensee's corrective actions program.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

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

Testing subsequent to the following activities was observed and evaluated:

- Unit 0 train B essential service water blowdown isolation valve repair completed on April 18, 2003;
- Unit 1 train B emergency diesel generator overhaul completed on May 12, 2003;
- Unit 1 train B emergency diesel generator relay replacements completed on May 12, 2003;
- Unit 1 train B auxiliary feedwater pump work window completed on May 18, 2003;
- Train G essential service water cooling tower fan following motor replacement on May 21, 2003; and
- Unit 2 train B containment spray following maintenance activities completed on June 10, 2003.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors witnessed selected surveillance testing and/or reviewed test data to verify that the equipment tested using the surveillance procedures met the TS, the Technical Requirements Manual, the UFSAR, and licensee procedural requirements, and demonstrated that the equipment was capable of performing its intended safety functions. The activities were selected based on their importance in verifying mitigating systems capability and barrier integrity. The inspectors used the documents listed in the Attachment at the end of this report to verify that the testing met the frequency requirements; that the tests were conducted in accordance with the procedures including establishing the proper plant conditions and prerequisites; that the test acceptance criteria were met; and that the results of the tests were properly reviewed and recorded. In addition, the inspectors interviewed operations, maintenance and engineering department personnel regarding the tests and test results.

The inspectors evaluated the following surveillance tests:

- Unit 1 train A auxiliary feedwater pump undervoltage simulated start surveillance on April 26, 2003;
- Unit 1 train A charging pump ASME (American Society of Mechanical Engineers) surveillance test on April 29, 2003;
- Unit 1 train B residual heat removal pump ASME surveillance test on May 7, 2003;
- Unit 2 train B safety injection pump ASME surveillance test on May 8, 2003;
- Unit 1 train B emergency diesel generator semi-annual surveillance test on May 12, 2003;

- Unit 1 train B auxiliary feedwater pump ASME surveillance test on May 18, 2003; and
- Unit 2 train B containment spray system ASME valve stroke time testing on June 10, 2003.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed and evaluated the following temporary plant modification on risk-significant equipment:

- Engineering Change 340908, supply design sketch and install guard plate after removal of a security barrier on May 5 2003;
- Engineering Change 343158, establish a freeze seal on for the repair of 2SX173, completed June 3, 2003; and
- Engineering Change 343159, removal of the internals of Valve 2SX173, completed on June 3, 2003.

The inspectors reviewed these temporary plant modifications to verify that the instructions were consistent with applicable design modification documents and that the modification did not adversely impact system operability or availability. The inspectors interviewed operations, engineering and maintenance personnel as appropriate and reviewed the design modification documents and the 10 CFR 50.59 evaluations against the applicable portions of the UFSAR. The documents listed in the Attachment at the end of this report were also used by the inspectors to evaluate this area.

b. Findings

No findings of significance were identified

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed the emergency response activities associated with the simulator training completed on May 19, 2003. Specifically, the inspectors verified that the emergency classification and simulated notifications were properly completed, and that the licensee adequately critiqued the training. Additionally, the inspectors determined that the results were properly counted in the Performance Indicators for emergency preparedness.

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

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Public Radiation Safety

2PS3 Radiological Environmental Monitoring and Radioactive Material Control Programs (71122.03)

.1 Review of Environmental Monitoring Reports and Data

a. Inspection Scope

The inspectors reviewed the 2001 and 2002 Annual Radiological Environmental Operating Reports to assess sampling location commitments, monitoring and measurement frequencies, land use census, the vendor laboratory's interlaboratory comparison program, and data analysis. Anomalous results including data, missed samples, inoperable, or lost equipment were evaluated. The review of the Radiological Environmental Monitoring Program (REMP) was conducted to verify that the REMP was implemented as required by the Offsite Dose Calculation Manual (ODCM), Technical Specifications, and the Technical Requirements Manual (TRM), and that changes, if any, did not affect the licensee's ability to monitor the impact of radioactive effluent releases on the environment. Additionally, the most recent corporate audit of the licensee's REMP vendor was reviewed to verify that the vendor laboratory performance was consistent with licensee and NRC requirements.

b. Findings

No findings of significance were identified.

.2 Walkdowns of Radiological Environmental Monitoring Stations and Meteorological Tower

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 (TLDs) to verify that their locations were consistent with their descriptions in the ODCM and to evaluate the material condition of these stations.

The meteorological monitoring site was observed to validate that sensors were adequately positioned and operable. The inspectors reviewed the 2001 and 2002 Annual Radiological Environmental Operating Reports and a sampling of monthly reports provided by the meteorological services vendor, to evaluate the onsite meteorological monitoring program's data recovery rates, routine calibration, and maintenance activities, and non-scheduled maintenance activities. The review was conducted to verify that the meteorological instrumentation was operable, calibrated and maintained in accordance with licensee procedures. The inspectors also verified that readouts of wind speed, wind direction, and atmospheric stability measurements were available in the control room.

b. Findings

No findings of significance were identified.

.3 Review of REMP Sample Collection and Analysis

a. Inspection Scope

The inspectors accompanied the REMP vendor representative to observe the collection and preparation of particulate air filters to verify that representative samples were collected in accordance with vendor procedures and the ODCM. The inspectors observed the technician perform air sampler field check maintenance to verify that the air samplers were functioning in accordance with vendor and licensee procedures. Calibration and maintenance records (June 2002 to April 2003) for the eight air sampling stations were reviewed to verify that the equipment was being maintained as required. Additionally, the inspectors observed the collection of surface water samples from the Rock River (upstream and downstream of the effluent discharge point), and the collection and preservation of milk samples to assess the licensee's compliance with ODCM and TRM requirements. The environmental sample collection program was compared with the ODCM to verify that samples were representative of the licensee's release pathways. Additionally, the inspectors reviewed results of the vendor laboratory's interlaboratory comparison program to verify that the vendor was capable of adequately preparing and analyzing environmental samples for a variety of radioisotopes.

b. Findings

No findings of significance were identified.

.4 Unrestricted Release of Material from the Radiologically Controlled Area

a. Inspection Scope

The inspectors evaluated the licensee's controls, procedures, and practices for the unrestricted release of material from radiologically controlled areas of the station to verify that: (1) radiation monitoring instrumentation used to perform surveys for unrestricted release of materials was appropriate; (2) instrument sensitivities were consistent with NRC guidance contained in Inspection and Enforcement Circular 81-07 and Health Physics Positions in NUREG/CR-5569 for both surface contaminated and volumetrically contaminated materials; (3) criteria for survey and release conformed to NRC requirements; (4) licensee procedures were technically sound and provided clear guidance for survey methodologies; and (5) radiation protection staff adequately implemented station procedures. In particular, the inspectors reviewed and observed the implementation of the controls used in the release of materials at the radiologically controlled area egress point in the Auxiliary Building (401' Elevation).

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed: (1) the results of recent focus area self-assessments of the REMP and Radioactive Material Control programs completed by the RP and Exelon Corporate staffs; (2) a Nuclear Oversight Continuous Assessment Report and field observations as they relate to the REMP and Radioactive Material Control programs; and (3) the licensee's condition report (CR) database and several individual CRs related to the REMP and Radioactive Material Control programs generated in calendar years 2001 through 2003. The inspectors evaluated the effectiveness of these processes to identify, characterize, and prioritize problems, and to develop and implement corrective actions.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP2 Access Control (Identification, Authorization and Search of Personnel, Packages, and Vehicles) (IP71130.02)

a. Inspection Scope

The inspectors reviewed the licensee's protected area access control testing and maintenance procedures. The inspectors observed licensee testing of all protected area access control equipment to determine if testing and maintenance practices were performance based. On two occasions, the inspectors observed in-processing search of personnel, packages, and vehicles to determine if search practices were conducted in accordance with regulatory requirements.

The inspectors reviewed security related event reports and safeguard log entries associated with the access control program for the period April 1, 2002 through May 13, 2003. The inspectors also reviewed the licensee's corrective action program to determine if security related issues associated with the access control program were appropriately identified and resolved.

b. Findings

No findings of significance were identified.

3PP3 Response to Contingency Events (71130.03)

a. Inspection Scope

The inspectors walked down the licensee's protected area intrusion alarm system to identify potential vulnerabilities. The inspectors, accompanied by licensee security representatives, observed testing of selected protected area intrusion alarm zones. Alarm zone detection was evaluated by conducting various testing methods.

The inspectors also reviewed the effectiveness of alarm station personnel to recognize and identify activities in the protected area alarm detection zones on the assessment monitors. The inspectors also reviewed the field of view provided by the assessment aids to ensure compliance with the licensee's security plan.

The inspectors also reviewed a sample of licensee force-on-force drill records, and interviewed security management personnel to determine if the licensee had appropriately identified and resolved issues associated with the contingency response program.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

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

.1 Reactor Safety Strategic Area

The inspectors sampled the licensees submittals for performance indicators (PIs) and periods listed below. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in revision 1 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guidance were used. The following PIs for units were reviewed:

- unplanned scrams per 7000 critical hours (April 2002 to March 2003);
- unplanned power changes per 7000 critical hours (April 2002 to March 2003);
- scrams with loss of normal heat removal (April 2002 to March 2003); and
- reactor coolant system specific activity (July 2002 through March 2003).

The inspectors reviewed each of the licensee event reports from April 2002 to March 2003, determined the number of scrams that occurred, evaluated each of the scrams against the performance indicator definitions, and verified the licensee's calculation of critical hours for both units. The inspectors also reviewed power history data for both operating units from, determined the number of power changes greater than 20 percent full power that occurred, and evaluated each of those power changes against the performance indicator definition.

For the reactor coolant system specific activity PI, the inspectors reviewed the licensee's Chemistry Department records and selected isotopic analyses to verify that the greatest Dose Equivalent Iodine (DEI) value obtained during those months corresponded with the value reported to the NRC. The inspectors also reviewed selected DEI calculations to verify that the appropriate conversion factors were used in the assessment as required by Technical Specifications. Additionally, on May 22, 2003, the inspectors observed a chemistry technician obtain and analyze a reactor coolant sample for DEI to verify adherence with licensee procedures for the collection and analysis of reactor coolant system samples.

b. Findings

No findings of significance were identified.

.2 Radiation Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensees submittals for PI listed below for the period April 2002 to March 2003. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in revision 1 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guidance were used. The following PI was reviewed:

- public radiation safety.

The inspectors reviewed the licensee's assessment of its performance indicator for public radiation safety by reviewing the dose records related to both liquid and gaseous effluent releases from the station from April 2002 to March 2003, to determine if this data was adequately assessed and reported. Since no reportable events were identified by the licensee for the 2nd through 4th quarters of calendar year 2002 and for the 1st quarter of calendar year 2003, the inspectors compared the licensee's data with the condition report database for these time periods to verify that there were no unaccounted for occurrences in the Public Radiation Safety Performance Indicator as defined by the guidance.

b. Findings

No findings of significance were identified.

.3 Safeguards Strategic Area

a. Inspection Scope

______The inspectors verified the data for the following PIs:

- Physical Protection Performance Indicators pertaining to Fitness-For-Duty Personnel Reliability;
- Personnel Screening Program; and
- Protection Area Security Equipment.

Specifically, a sample of plant reports related to security events, security shift activity logs, fitness-for-duty reports, and other applicable security records were reviewed for the period between April 2002 through April 2003.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Routine Reviews of Identification and Resolution of Problems

a. Inspection Scope

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

b. Findings

No findings of significance were identified.

.2 Detailed Review - 2C Steam Generator Foreign Material Induced Tube Leak

Introduction

On July 24, 2001, the licensee determined that the 2C steam generator (SG) had indications of primary to secondary leakage. The leakage was estimated to be less than five gallons per day (gpd). The licensee monitored the leakage and established contingencies to shutdown and repair the steam generator if the primary to secondary leakage increase to a value greater than 75 gpd, which is one-half the leak rate allowed by the TS. On June 22, 2002, as a result of a step increase in primary to secondary leakage from 53 gpd to 63 gpd in the 2C SG, the licensee shutdown Unit 2. A maximum primary to secondary leak rate of 76 gpd was noted during the shutdown of the unit. (The inspector's review of the shutdown was provided in NRC Inspection Report 50-455/02-05, Section 1R14.)

During the resulting forced outage, the licensee identified tube 43-23 was the cause of the primary to secondary leakage. In addition, two adjacent tubes (43-22 and 43-24), were identified as degraded. The licensee performed eddy current bobbin exams in this area of the SG with no indications of foreign material identified; however, the wear indications on the damaged and degraded tubes were determined to be caused by a foreign object.

Prior to restarting the plant, the licensee analyzed the leaking tube and concluded that the burst pressure of the tube would have been in excess of 4600 pounds per square inch (psi). Furthermore, the results of this analysis were confirmed by in situ testing which reach a pressure of 4700 psi with no evidence of tube burst. These results demonstrated that the tubes would have met the design requirements for withstanding the analyzed plant transients. The licensee also reviewed prior 2C SG eddy current exams results and verified that no previous indications were present in the area of the damaged tubes. Subsequently, the licensee plugged the leaking tube and the two degraded tubes and the unit was returned to service on June 27, 2002.

During the next Unit 2 refueling outage, September 2002, the licensee completed visual inspections near the leaking tube and identified and retrieved two pieces of foreign material. The location of these two pieces was at the second tube support plate in the preheater section of the cold leg side. These two pieces were similar in appearance and structure and described as hollow sheathing/cable 1/8" in diameter and measuring approximately 3" and 3.5" in length. Through lab analysis, the licensee determined that the two pieces were originally one piece. The licensee determined that fatigue induced failure of the object was caused during fretting of the damaged tube, and after the failure, the two pieces migrated downstream of the damaged tube. The licensee also determined that the object did not originate from plant equipment, and believed that increased feedwater flows resulting from the power uprate may have caused dormant objects to migrate through systems and to eventually come to rest in the SG.

As a result of the foreign material identified in the 2C SG, the licensee completed an extensive foreign object search and retrieval (FOSAR) visual inspection of the 2C SG preheater region that resulted in the identification and retrieval of more foreign objects. Eddy current bobbin exams were completed in the SGs and identified additional foreign objects in the 2D as well as 2C SGs. In all, 38 objects were retrieved and eleven tubes plugged during the refueling outage.

Based on the locations of past inspections and the internal flow characteristics of the 2C SG, the licensee determined that the foreign object entered the SG via the lower feedwater nozzle. However, the specific origin of the object could not be determined. The licensee completed a review of the work performed on the secondary side systems over the past five years, but were unsuccessful in determining the specific origin of the object. The licensee concluded that the foreign material introduced into the SG resulted from inconsistent foreign material exclusion (FME) controls and standards during previous maintenance activities.

The inspectors reviewed the root cause analysis associated with Condition Report 123810 to assess the adequacy of the licensee's evaluation, and corrective actions. In addition the inspectors assessed the licensee's performance resulting in the 2C SG tube leak.

a. Prioritization and Evaluation of Issues

(1) Inspection Scope

The inspectors reviewed the root cause analysis evaluation associated with Condition Report 123810, "2C Steam Generator Foreign Material Induced tube Leak."

(2) Issues

The licensee's analysis utilized an event and causal factor chart, and they evaluated the results using TAP ROOT ®, Barrier and Cause and Effects analytical methods. The information evaluated by the licensee during their investigation included review of:

- procedures;
- packages;
- surveys;
- lab analysis; and
- training material.

In addition, the licensee interviewed applicable personnel to gain insights associated the issue.

As a result of the root cause analysis, the licensee identified three causal factors:

- No routine preventative maintenance existed for FME visual inspections of the preheater regions of the Unit 2 SGs;
- Incorrect application of flexitallic gaskets in high-pressure applications; and
- Supervisors and workers not held accountable for upholding FME standards.

The inspectors noted that data utilized in the root cause analysis matched the independently obtained source documents. Additionally, the inspectors reviewed the associated TAPROOT ® evaluation charts and compared the thoroughness of the evaluation with the guidance provided by the TAPROOT ® text book and TAPROOT ® Cause Tree Dictionary, with no problems noted.

b. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspections verified that the corrective actions planned adequately addressed the causes identified by the root cause analysis. The inspectors selected at random a sample of completed actions to verify that they met the specified closure criteria. Regarding the corrective actions still in the process of being completed, the inspectors noted that the due dates were not being routinely extended. Although the inspectors were unable to assess the effectiveness of the licensee's corrective actions, the inspectors noted that the licensee has included as part of the corrective actions several assessments of the effectiveness of their actions.

(2) Findings

A Green finding was identified through a self-revealing event when, during previous maintenance activities, workers and supervisors failed to uphold the FME standards by allowing foreign material into the 2C SG. This resulted in a steam generator tube leak. The finding was not considered a violation of regulatory requirements.

Analysis

The inspectors determined that the failure to uphold the FME standards was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on April 29, 2002. The inspectors determined that the finding was more than minor since it involved the human performance attribute that affected the reactor coolant system portion of the barrier integrity cornerstone objective. The inspectors also determined that this deficiency affected the cross-cutting area of Human Performance.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," because the finding was associated with the integrity of the reactor coolant system. For the Phase 1 screening, it was determined that since the finding was associated with the reactor coolant system barrier, the inspectors assessed the issue through a Phase 2. A phase 2 risk assessment was performed using the steam generator tube rupture worksheet with a duration of >30 days. Because the in-situ tube testing demonstrated that the tubes were always operable and capable of withstanding design basis transient pressures, the inspectors determined that there was no increase in the initiating event frequency. Completing the Phase 2 worksheets determined that the SG tube leakage issue was of very low safety significance, Green (FIN 05000455/2003003-03). The regional SRA reviewed the Large Early Release Frequency (LERF) implications of the finding and determined that the change in LERF would not increase the risk characterization from Green because (1) the plant did not operate at-power with one or more tubes that should have been but were not repaired or plugged based on previous tube inspection results, (2) the tubes in question were found to meet required performance criterion for pressure, as demonstrated by the in-situ testing and (3) the leakage rate of the tubes was below the 150 gpd TS criteria and below the calculated "accident leakage" rate.

Enforcement

Because the inspectors and the licensee were unable to determine when the foreign material was introduced into the steam generator, the inspectors could not conclude that a violation of regulatory requirements occurred. The licensee entered the issued into its corrective action system as Condition Report 123810, "2C Steam Generator Foreign Material Induced Tube Leak," dated September 9, 2002.

4OA3 Event Follow-up (71153)

.1 (Closed) Licensee Event Report (LER) 50-454-2003-001-00: "Control Room Ventilation System Alignment Results in Inoperable Radiation Monitors Without Taking Required Actions per the Technical Specifications."

The inspectors reviewed the LER, related condition reports and evaluations and other documents as listed in the Attachment at the end of this report. The inspectors also discussed the details of the condition with the appropriate members of the licensee's engineering staff. In addition, the inspectors completed a walkdown of the applicable portions of the control room ventilation system.

As discussed in the subject LER, on January 27, 2003, the licensee determined the unit common VC filtration system actuation instrumentation radiation monitors were not operable when VC was manually aligned to the turbine building makeup air intake. This was because there was little or no air flow past the monitors when aligned in that mode. The licensee also reported that a design change made before the beginning of plant operation had been inadequately evaluated and had rendered the system less capable of performing its design function. Specially, this design change removed the Engineered Safety Feature-Safety Injection (ESF-SI) actuation signal to secure the miscellaneous ventilation system, which allowed for possible unfiltered air in-leakage to the control room enveloped beyond the originally analyzed amount.

The licensee corrective actions, as described in the LER, included interim controls and instructions for operation of the system and were to include revisions to the surveillance and emergency procedures. In addition, the licensee conducted an evaluation confirming that this condition did not preclude the fulfillment of the VC safety function to prevent dose to the control room personnel from exceeding General Design Criteria 19 limits. The result of this evaluation was documented in the licensee's supplement to the LER issued on May 23, 2003.

The inspectors determined that the licensee-identified issues were more than minor because they were caused by performance deficiencies associated with the attributes of procedure quality and design control. Both deficiencies affected the barrier integrity cornerstone objective of providing reasonable assurance that physical design barriers would protect the operators from radio-nuclide releases caused by accidents or events. The findings would also become more safety significant if left uncorrected because the probability of an actual event which would result in a high radiation condition in the outside air would have increased with time. The inspectors determined that having the VC system filtration actuation system inoperable in excess of the TS allowed outage time during surveillance testing of the VC system also affected the cross-cutting area of human performance because operators failed to recognize the surveillance test alignment resulted in the inoperability of the system.

The findings were determined to have very low safety significance (Green) in the SDP Phase 1 Screening Worksheet of Manual Chapter 0609, Appendix A, Attachment 1, because the findings only represented a degradation of the radiological barrier function provided for the control room. The licensee entered these issues into its action tracking system as CR 141542. The enforcement aspects of these licensee-identified findings are described in Section 4OA7. This LER is closed.

.2 (Closed) Licensee Event Report 50-454-2003-001-01: "Control Room Ventilation System Alignment Results in Inoperable Radiation Monitors Without Taking Required Actions per the Technical Specifications." Supplement 1. The licensee submitted Supplement 1 to LER 50-454-2003-001 to provide confirmation that the condition would not have resulted in exceeding the General Design Criteria 19 limits. The inspectors reviewed the information provided in Supplement 1 to LER 50-454-2003-00, and the supporting documentation and acknowledged that the General Design Criteria limits would not have been exceeded. Supplement 1 of the LER did not raise any new issues or change the conclusions of the initial review which is documented in Section 4OA3.1 of this report. This LER is closed.

.3 (Closed) Licensee Event Report (LER) 50-454-2003-002-00: "Two Main Steam Safety Valves Lift Setpoints Found Out of Tolerance During Testing Due to Unknown Causes." On February 16, 2003, during mid cycle testing, the licensee identified two of six main steam safety valves (MSSV) on Unit 1 were below the Technical Specification limit of 3 percent of lift pressure. After identifying each test failure, the licensee entered into the appropriate Technical Specification LCO, adjusted the MSSV setpoint, and retested the valve satisfactorily within the TS allowed outage time. The licensee evaluated the impact of the two MSSVs being out of tolerance and concluded that the condition was bounded by the safety analysis report. In addition, the licensee was assessing whether this condition resulted from differences between the in situ testing performed in February 2003 and the vendors testing used following refurbishment using a steam boiler, which will be documented in a supplement to the LER. The inspectors reviewed and concurred with the licensee's evaluation. The inspectors determined that the issue has greater significance than a similar issue described in IMC 612, "Power Reactor Inspection Reports," Appendix E Section 2.a. This licensee-identified issue involved a violation of TS 3.7.1, Main Steam Safety Valves. The enforcement aspects of this issue are discussed in Section 4OA7. This LER is closed.

4OA4 Cross-Cutting Findings

.1 A finding described in Section 1R12 of this report had as its primary cause a human performance deficiency, in that, the licensee did not adequately specify in procurement documentation an adequate test method for determining total water concentration. This resulted in additional unavailability time of the emergency diesel while the hydraulic oil was replaced unnecessarily.

.2 A finding described in Section 1R13 of this report had as its primary cause a human performance deficiency, in that, despite the availability of a computer software tool that would have indicated additional evaluation was required additional risk evaluation was not completed.

.3 A finding described in Section 4OA2.2 of this report had as its primary cause a human performance deficiency, in that, during previous maintenance activities, supervisors and workers did not uphold FME standards resulting in a steam generator tube leak.

.4 A licensee identified violation described in Section 4OA3.1 of this report had as its primary cause a human performance deficiency, in that, operators failed to recognize that the surveillance test alignment resulted in inoperability of the VC system.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. R. Lopriore and other members of licensee management at the conclusion of the inspection on June 26, 2003. 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

An interim exit was conducted for:

- Safeguards Inspection with Mr. S. Stimac on May 16, 2003.
- Radiation Protection inspection with Mr. S. Kuczynski on May 23, 2003.

4OA7 Licensee-Identified Violations

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

Cornerstone: Mitigating Systems

1. Technical Specification 3.7.1 required that MSSVs be operable as specified in TS Table 3.7.1-2 or within four hours reduce power to less than or equal to that specified in TS Table 3.7.1-1. Furthermore, if this action was not completed in the specified time, the plant was required to be in Mode 3 in six hours. Contrary to this, as described in LER 50-454-2003-002-00, on February 16, 2003, the lift settings for MSSV 1MS015B and 1MS013A were found below the three percent limit allowed in TS Table 3.7.1-2. Based on engineering judgement, it lis likely that the valves were outside of the TS value in excess of the time allowed by the TS limiting condition for operation. This violation is of very low safety significance because the condition was bounded by the safety analysis report. The licensee entered this event into its action tracking system as CR 144797.

2. 10 CFR Part 50, Appendix B, Criteria III, "Design Control," requires, in part, that measures be established to assure that applicable regulatory requirements and

the design basis are correctly translated into specifications, procedures, and instructions. Specifically, NUREG-0876, "Safety Evaluation Report related to the operation of Byron Station, Units 1 and 2", Sections 6.3.2 and 8.4.3 took credit for power lockout of the Spurious Valve Actuation Group (SVAG) valves in accordance with Branch Technical Position BTP ICSB 18 (PSB), "Application of the Single Failure Criterion to Manually-Controlled Electrically-Operated Valves". Per Branch Technical Position BTP ICSB 18 (PSB), manually-controlled "active" valves (i.e. valves that are required to open or close in various safety system operational sequences) were required to be operated from the main control room. Contrary to the above, on or before October 23, 1985, the design basis for the Units 1 and 2 electrical systems related to lockout power to manually controlled electrically-operated valves was not correctly translated into specifications, procedures, and instructions. Specifically, this design basis was not correctly translated into the Emergency Operating Procedures, which required local operator actions, not control room actions, to energize the motor control center compartments for certain “active” SVAG valves of the Emergency Core Cooling System (ECCS). This violation was considered more than minor because it was related to the procedure quality that affected the reliability to operate mitigating system equipment, and was determined to be of very low safety significance because subsequent evaluation concluded it did not result in a loss of ECCS equipment function. The licensee entered this event into its action tracking system as CR 122608.

Cornerstone: Barrier Integrity

1. TS 3.3.7 required that two detectors in each train of the VC system filtration actuation system be operable for gaseous activity during operations in Modes 1 through 5 and in Mode 6 during movement of irradiated fuel assemblies. Contrary to this, as described in LER 50-454-2003-001-00, none of the gaseous detectors and neither train of the VC system filtration system actuation system were operable, under certain conditions, from the beginning of plant operations. This was due to inadequate flow past the detectors and the inability to automatically align as intended in the case of high radiation in the outside air if the system was already manually aligned to the turbine building makeup air source. The licensee entered this event into its action tracking system as CR 141542. This finding is of very low safety significance because it only represented a degradation of the radiological barrier function provided for the control room.

2. 10 CFR 50, Appendix B, Criteria III, “Design Control,” required, in part, that design control measures shall provide for verifying and checking the adequacy of design. Contrary to the above on or about August 21, 1986, the licensee failed to verify the adequacy of the design with respect to the impact on control room habitability as noted in Engineering Design Change P-639, “Delete Safety Injection Signal from Miscellaneous Ventilation System, Control Room Office HVAC,”. The licensee entered this event into its action tracking system as CR 141542. This finding is of very low safety significance because it only

represented a degradation of the radiological barrier function provided for the control room.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
R. Lopriore, Site Vice President
S. Kuczynski, Plant Manager
B. Adams, Engineering Director
D. Combs, Site Security Manager
D. Goldsmith, Radiation Protection Director
W. Grundmann, Regulatory Assurance Manager
D. Hoots, Maintenance Manager
S. Kerr, Chemistry Manager
R. Kolo, Training Manager
R. Krohn, Security Analyst
S. Leach, Radiation Protection Instrument Coordinator
M. Mareth, Site Security Force Manager, TWC
E. Steinke, Chemistry
S. Stimac, Operations Manager
D. Thompson, Lead HP Technical

Nuclear Regulatory Commission
A. Stone, Chief, Projects Branch 3, Division of Reactor Projects

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000455/2003003-01	NCV	Failure to specify an adequate emergency diesel generator Hydraulic oil sampling process which led to increased unavailability of the diesel.
05000454/2003003-02	NCV	Failure to assess risk associated with the isolation of a pressurizer PORVafter closing its associated block valve.
05000455/2003003-03	FIN	Failure of supervisors and workers to uphold the foreign material exclusion standards resulted in a steam generator tube leak.

Closed

50-454-2003-001-00	LER	Control room ventilation system alignment results in inoperable radiation monitors without taking required actions per the technical specifications.

50-454-2003-001-01	LER	Control room ventilation system alignment results in inoperable radiation monitors without taking required actions per the technical specifications.
50-454-2003-002-00	LER	Two main steam safety valves lift setpoints found out of tolerance during testing due to unknown causes.

Discussed

None

LIST OF DOCUMENTS REVIEWED

1R01 Adverse Weather Protection

CR 157951; Unplanned Entry into Byron Abnormal Operating Procedure (0BOA) ENV-4, Seismic, May 8, 2003
WO 570291; 0BOSR Z.7.A.2-1, Deepwell Pump Operability Monthly Surveillance, May 22, 2003
CR 160235; Focus Area Self Assessment (FASA) on Summer Readiness, May 23, 2003
CR 162379; Zone 80 Housekeeping Walkdown/NRC Loose Debris Concern, June 6, 2003 [1]
OP-AA-108-109; Attachment 3 - System Engineering System Readiness Review for Circulating Water, and Essential Service Water, Revision 1
OP-AA-108-109; Seasonal Readiness, Revision 1

1R04 Equipment Alignment

Technical Specifications
CR 155679; Failure to Log Bus 241 and 242 Load in NSO Log, April 22, 2003
BOP Ap-54; Restoring Unit 2 System Auxiliary Transformer 242-1 and 242-2 During Power Operation, Revision 8
Byron's Archival Operations Narrative Logs; April 21,2003 and before April 24, 2003
Regulatory Guide 1.33; Quality Assurance Program Requirements (Operation), Revision 2
Byron Station One Line Diagram; 6E-0-4001, Revision L
BOP AP-E2; Unit 2 Auxiliary Power Electrical Lineup, Revision 4
BOP AP-E1; Unit 1 Auxiliary Power Electrical Lineup, Revision 6
BOP AP-53; Isolating Unit 2 System Auxiliary Transformer 242-1 and 242-2 While Unit is at Power, Revision 12
CR 157088; 1B Seal Injection Valves Found Not Fully Closed, (NRC Identified), May 1, 2003
BOP AP-E1; Auxiliary Power Unit 1Electrical Lineup, Revision 6

BOP AP-E2; Auxiliary Power Unit 2 Electrical Lineup, Revision 4
BOP AF-M1A; Auxiliary Feedwater System Train A Valve Lineup, Revision 3
BOP AF-E1A; Auxiliary Feedwater System Train A Electrical Lineup, Revision 1
BOP RH-E2A; Residual Heat Removal System Train A Electrical Lineup, Revision 2
BOP RH-M2A; Residual Heat Removal System Train A Valve Lineup, Revision 5
BOP CW-E1; Circulating Water System Electrical Lineup, Revision 8
BOP CW-M1; Circulating Water System Valve Lineup, Revision 22
M-144; Diagram of Circulating Water, Revision T

1R05 Fire Protection

Byron/Braidwood Stations Fire Protection Report; Amendment 20
BAP 1100-7; Fire Prevention for Transient Combustibles, Revision 10
BAP 1100-7A1; Minor Transient Combustibles, Revision 1
BAP 1100-9; Control, Use, and Storage of Flammable and Combustible Liquids and Aerosols, Revision 6
BAP 1100-16; Administrative Controls for Required Fire/Flood Watch Inspections, Revision 6
OP-AA-201-003; Fire Drill Scenario 6, Clean and Dirty Oil Storage Tank Room, Revision 1
OP-AA-201-003; Fire Drill Record, Clean/Dirty Oil Storage Tank Room, Revision 5, May 4, 2003
OP-AA-201-004; Fire Prevention for Hot Work, Revision 5
Hot Work Permit; Work Request 99280629,07,31,09,33, June 2, 2003
CR 159429; RCP Oil Addition While RCP is Running, May 18, 2003
Nuclear Event Report; LS-03-026 Green Sherwin Williams Epoxy Floor Paint Flame Spreading Rating May Exceed Noncombustible Limits, March 19, 2003
CR 162836; Procedure Compliance on OP-AA-201-004, Fire Prevention for Hot Work, June 11, 2003 [1]

1R06 Flood Protection Measures

CR 116930; The Equipment Drain Line in the 2A and 2B Auxiliary Feedwater Pumps is Plugged, July 24, 2002
CR 157064; Housekeeping Items Identified, May 02, 2003 [1]
Calculation HELB-8; Confirmation of Safe Shutdown Capability After Auxiliary Building Flooding, Revision 1, April 15, 1986
CR 121511; 2B Pump Room Drain Completely Plugged, September 4, 2002
CR 133982; Long Standing Equipment Deficiencies, December 4, 2002
Work Request 980132919; ESS SW Pump Leak Detect Sump, Every 3 Year Calibration of Flood Level Switch, June 9, 2000
BAR 0-38-D9; Fire Pump DSCH Press Lo-2, Revision 1
Internal Flooding Analysis Notebook Byron and Braidwood Station, BB PRA-012, Revision 2
BAP 1100-3T2; Plant Barrier Impairment Log, Revision 2
OBOSR WF-SA1; Auxiliary Building Floor Drain Semi-Annual Surveillance, Revision 1
WR 990037231 01; Auxiliary and FHB Floor Drains System - Hydrolyze U0, U1, U2 Auxiliary Drains, June 27, 2000

WO 554211; Vault/Cable Inspect
WO 99210103; Perform Calibration Check on 1A Steam Generator Pump Leak Detector, July 20, 2002
WO 99208161; Perform Calibration Check on 2A Steam Generator Pump Leak Detector Sump Level Switch, October 21, 2002
WO 363588; Perform Calibration Check on 1B Steam Generator Pump Leak Detector Sump Level Switch, March 19, 2002
Calculation WR-BY-PF-10; Effect of Local Probable Maximum Precipitation (PMP) At Plant Site, Revision 5
Calculation 3C8-1281-001; Auxiliary Building Flood Level Calculations, Revision 11
WO 476900; Auxiliary Building Floor Drain Semi-Annual Surveillance , March 17, 2003
PIF 454-201-95-1058; Open Ventilation System Connecting the Auxiliary Building Drain Room and Auxiliary Building Equipment Room to the SX Pump Room All Three Rooms are Designed to be Watertight Compartments
NRC Information Notice 2002-12; Submerged Safety-Related Electrical Cables, March 21, 2002,
Regulatory Guide 1.59; Design Basis Floods for Nuclear Power Plants, Revision 2, August 1977

1R07 Heat Sink Performance

CR 141451; As Found Condition of 2A SX Pump Lube Oil Cooler (2SX01AA), January 28, 2003
CR 137005; As Found Acceptance Criteria for 2SX01AB Was Not Met, December 20, 2002

1R11 Licensed Operator Requalification Program

Scenario Number 03-3-1 Revision 0, April 10, 2003
NSP EP-AA-1002; Radiological Emergency Plan Annex for Byron Station, Revision 14
CR 128854; Ineffective CA for Potential to Air Bind both CS Pumps, October 25, 2002
CR 158917; Procedure Deficiencies Noted During LORT, May 14, 2003

1R12 Maintenance Effectiveness

CR 156866; Hi-2 Level Isolation on the 2D First Stage Reheater Drain Tk, May 1, 2003
CR 160689; 1D Second Stage RDT Emergency AOV Non-Responsive, May 25, 2003
CR 054086; Failure of 27A HP FW Heater Normal Drain Valve, June 5, 2003
CR 128074; 1HD005D Stroke Failure, October 18, 2002
CR 152058; 1HD041B; Failure fecting 16B FW Heater Level Control, April 2, 2003
CR 156930; Air Regulator Spring Range Can affect AOV Operating Margins, April 7, 2003
CR 053845; 2HD008A (27A FWH Outlet Control) Sticky Operation, June 3, 2003
CR 119978; OC 254-Heater Drain Temperature Sensitivity, Assignment 08
CR 056025; 1C First Stage RHDT Normal Level Controller, June 27, 2001
CR 077953; 1HD046A/B Flow Control Problems, October 5, 2001
CR 133062; MSR Shell Emergency Drain Drift Open-Degraded Level Controller, November 21, 2002

CR 110295; Unit 1 Heater Drain Valves Oscillation, June 1, 2002
CR 157388; HD Flow Control Valve (HD046s) Anomalies, May 5, 2003
CR 156304; Air Regulator Setting Spec on Masoneilan Drawing is Not High Enough, April 7, 2003
CR 157305; HD Level Control Issues from Week of 4/1/03, April 3, 2003
List of Open and Closed Condition Reports Associated with Heater Drains, April 2001 - April 2003
CR B2000-03153; PCM Recommended PM Frequency for HD AOVs Would Not Prevent Failures, October 17, 2000
Purchase Requisition 368093; Testing of Lubricants & Diesel Fuel, January 27, 1999
Memo on Test Results; Mobil Devac 1340, June 17, 2003
Memo; Mobil Delac 1340 Sample Results
Exelon PowerLabs; Analysis of Mobil Delvac 1340 Engine Oil, June 17, 2003
Procedure Evaluation 15612; Requirements for Commercial Grade Dedication of Catalog ID 3940-2, March 23, 2002
Procurement Evaluation 3585
CR 161868; Mechanical Governor Oil Sight Glass Filled to the Top, June 4, 2003
Maintenance Rule-Performance Criteria, System Heater Drains
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Byron 02 Monthly Ship System Report; Heater Drains, March 2003
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Temporary Leak Repair Permit; Top and Bottom Flange on 1LC-HD101, April 7, 2003
CC-AA-404; Maintenance Specification: Application Selection, Evaluation and Control of Temporary Leak Repairs, Revision 4
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NUMARC 93-01; Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2
WR 97314 & 97316; Trouble Shoot Temperature Sensitive Component, May 6, 2003
CR B2001-02569; 2HD008A Diaphragm Failure During Restoration, June 5, 2001
AR 119978; OC 265-HD046A/B Oscillations, Assignment 12
AR 89643; Perform Review to Improve Level Controller Life Action from CCA 144056, Assignment 17
AR 89643; Contact Masoneillan About Bellows Gaskets, Assignment 10
AR 89643; Evaluate New PM Activity on Level controllers, Assignment 11
AR 89643; HD Level Controller Inspection During B1R12, Assignment 9
CR 148263; Unexpected Alarm-12C Heater Emergency Drain Valve Open, March 9, 2003
CR 145948; “C4" Code Removed from WO and Work Rescheduled, February 21, 2003
LS-AA-125-1003; Apparent Cause Evaluation Manual, Revision 2
LS-AA-125-1002; Common Cause Analysis Manual, Revision 2
CR 144056; Possible Increasing Trend of Number of Level Controller Wrs, February 10, 2003
CR 135536; 2C HD PP Secured After Abnormal PP S/U, December 13, 2002

1R13 Maintenance Risk Assessments And Emergent Work Control

Updated Final Safety Analysis Report

Byron Operating Department Policy 400-47; April 7, 2001, Revision 2
NSP ER-AA-600; Risk Management, Revision 2
NSP ER-AA-600 Risk Management, Revision 2
NSP ER-AA-310; Implementation of the Maintenance Rule, Revision 2
NSP WC-AA-101; On-line Work Control Process, Revision 6
Byron Station One Line Diagram; 6E-0-4001, Revision L
On-Line Maintenance Impact Review; Schedule Dates April 21, 2003 to April 27, 2003, Revision 6
On-Line Maintenance Schedule Review; Schedule Dates April 21, 2003 to April 27, 2003, Revision 6
On-Line Maintenance Approval Form; Unit 2 SAT 242-1 and SAT 242-2, Revision 6
Risk Configuration Sheet - Week of April 21, 2003
BOP AP-53; Isolating Unit 2 System Auxiliary Transformer 242-1 and 242-2 While Unit is at Power, Revision 12
ER-AA-600-1011; Risk Management Program, Revision 1
WC-AA-101; On-Line Work Control Process, Revision 6
Byron's Archival Operations Narrative Logs; April 21, 2003
Policy No: 400-47; Byron Operating Department Policy Statement, Revision 2
CR 132702; Work Carried Into November 21, 2002 Without Proper Online Risk Documentation, November 21, 2002
CR 133737; Online Risk Not Evaluated for Planned Activities, November 27, 2002
CR 153737; PMT Tests Are Not Screened for Production/Safety Risk, April 14, 2003
CR 154998; Potential of Averse Impact on Configuration Control, April 21, 2003
CR 158258; Protected Equipment Program, May 11, 2003
CR 158362; Online Risk Not Evaluated when PZR PORV Block vlv was Closed, May 5, 2003 [1]
CR 161143; Online Risk Not Evaluated for Emergent Failure, June 2, 2003

1R14 <u>Personnel Performance During Non-Routine Evolutions</u>

CR 150984; 1FW009B Oil Sample Color Not as Expected, March 27, 2003
CR 159391; 2A LP Turbine GS Problems, May 18, 2003
CR 159598; Unexpected Alarm Bank D Withdraw Limit Rod Stop C-11, May 18, 2003
Unit 2 Ramp Timeline For 2A RCP Oil Addition
MA-AA-716-230-1002; Vibration Analysis/Acceptance Guideline, Revision 0
MA-AA-716-230-1005; CSI RBMWare Database Setup Guideline, Revision 0
2BGP 100-4; Power Descension, Revision 20
BOP FW-2b; Shutdown of a Unit 2 Turbine Driven Main Feedwater Pump, Revision 8

1R15 <u>Operability Evaluations</u>

Technical Specifications
Technical Specification Basis
Technical Requirement Manual
Updated Final Safety Analysis Report
OD 03-002; Incorrect Hydraulic Fluid Found in the 1B Feedwater Isolation Valve and Unit 2 Main Steam Isolation Valves, Revision 2

ASTM D 6304-00; Standard Test Method for Determination of Water in Petroleum Products, Lubricating Oils, and Additives by Coulometric Karl Fischer Titration
Test Report (PO 4441); Governor Oil Test Results, June 17, 2003
ASTM D1744-92; Test Method for Water in Liquid Petroleum Products by Karl Fischer Reagent
EC 342220; Radiological Source Terms-Design Basis and Realistic, Revision 0
Regulatory Guide 1.183; Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors
Regulatory Guide 1.4; Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurize Water Reactors, Revision 2
Operability Evaluation 03-003, Operability of Spurious Valve Actuation Group (SVAG) Valves in the Emergency Core Cooling System, Revision 0
Operability Evaluation 03-003, Operability of Spurious Valve Actuation Group (SVAG) Valves in the Emergency Core Cooling System, Revision 2
Branch Technical Position ICSB 18 (PSB) Application of the Single Failure Criterion to Manually-Controlled Electrically-Operated Valves, Revision 2
NRC Inspection Manual Part 9900: Technical Guidance; Operable/Operability: Ensuring the Functional Capability of a System or Component
NRC Inspection Manual Part 9900: Technical Guidance; Resolution of Degraded and Nonconforming Conditions, October 8, 1997
NRC Generic Letter No 91-18, Revision 1; Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions
NRC Inspection Manual Part 9900: Technical Guidance; Maintenance - Preconditioning of Structures, Systems, and Components Before Determining Operability
WO 521074; OP Sample FWIV Hydraulic Fluid, March 31, 2003
MA-AA-716-230-1001; Used Oil Data Interpretation Guidelines, Revision 1
Position Paper; MSIV Technical Specification and Technical Requirement Manual (TRM) Entry, Revision 1
Project Number BYR-67605; Unit 2 MSIVs EH Fluid: 2MS001A, 2MS001B, 2MS001C & 2MS001D, June 13, 2003
OD 03-002; Incorrect Hydraulic Fluid Found in the 1B Feedwater Isolation Valve and Unit 2 Main Steam Isolation Valves, Revision 1
BOP MS-5; MSIV Accumulator Operability Check, Revision 11
1BOSR MS-W1; Unit One MSIV Checks Weekly Surveillance, Revision 5
CR 154855; Unit 1 MSIV Standby Accumulators Found Out of Tolerance, April 22, 2003
1BOL 7.2; Main Steam Isolation Valves (MSIVs) Technical Specification LCO 3.7.2, Revision 3
CR 150984; 1FW009B Oil Sample Color Not as Expected, March 27, 2003
CR 154888; Typo Identified in Operability Evaluation 03-003, April 18, 2003
CR 122608; OE14519-Westinghouse PWRs, September 11, 2002
CR 152573; Fyrquel in Main Steam Isolation Valve
CR 156628; Hydraulic Oil Level Is Not Visible in the Sightglass (1D MSIV), April 30, 2003
CR 157921; Issues Identified with 1D MSIV Troubleshooting Plan, May 8, 2003
CR 158801; 1D MSIV Standby N2 Press Loss Troubleshooting Results, May 9, 2003
CR 161101; Potential Effect of Fuel Rod Burst Calculation on SVAG Valve Operations Evaluation, May 29, 2003 [1]
Cr 161868; Mechanical Governor Oil Sight Glass Filled to the Top, June 4, 2003

CR 162279; 2B DG High Water Content in Mechanical Governor Oil, June 6, 2003
NUREG-1465; Accident Source Terms for Light-Water Nuclear Power Plants, February 1995,
CR 163059; Oil Program Questioning Attitude Identifies Testing Issue, June 12, 2003
Woodward Vendor Manual 82340C; EGB-Proportional Governor/Actuator with Hydraulic Amplifier Systems
EC 343232; Evaluation of Governor Oil Water Content
MA-AA-716-230-1001; Used Oil Data Interpretation Guideline, Revision 1
1BEP-1; Loss of Reactor or Secondary Coolant-Unit 1, Revision 103
1BEP-0; Reactor Trip or Safety Injection-Unit 1, Revision 104
1BEP ES-1.2; Post Loca Cooldown and Depressurization-Unit 1, Revision 102
50.59 Review; Revision of BEP/BwEP-0, -1, ES-1.2, ES-1.3, to Implement Changes to SVAG Valve Reenergization, Revision 1
AR 163399; Hot Rod Burst Phenomenon Poorly Described in the UFSAR, June 16, 2003
Validation/Verification Report; ½ BEP ES-1.3 Reactor Trip or Safety Injection, May 31, 2003
CR 163402; Minor Errors Found in UFSAR and TS Bases, June 13, 2003 [1]
1BEP ES-1.3; Transfer to Cold Leg Recirculation-Unit 1, Revision 100
CR 162941; SVAG Valve Operability (CR122608), June 11, 2003
CR 164099; CR 163263 Rebuttal, June 19, 2003
1BEP ES1.3, Transfer to Cold Leg Recirculation, Revision 1 (October 23, 1985)
1BEP ES1.3, Transfer to Cold Leg Recirculation Following Loss of Reactor Coolant - Unit 1, Revision 1 (March 31, 1984)
10 CFR 50.59 Evaluation TI-92-0235, UFSAR Change to Chapter 8 - DRP 4-033, August 22, 1991
CR 162279; 2B DG High Water Content in Mechanical Governor Oil, June 6, 2003
CR 163059; Oil Program Questioning Attitude Identifies Testing Issue, June 12, 2003
CR 163263, Rad Waste Operator Assuming Se Shutdown Duties, June 14, 2003
Unit ½ Standing Order 03-026; SVAG Valve Emergency Procedure Changes and R/W Operator Readiness, May 31, 2003
Cold Leg Recirculation Response Time Summary, May 28, 2002
AR 121599; Byron Station SME Review of OE 14519, September 4, 2002
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1R16 Operator Workarounds

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CR B2001-02461; Low Boration Flow Control Problem Continues to Produce Repeat Work Requests and Ers, May 25, 2001
CR B2001-02424; Unit 2 Primary Water Flow Controller Output Insufficient in Alt Dilute Mode, May 23, 2001
CR 128728; Collective Effectiveness Review for SOER 94-01 Ineffective, October 22, 2002

Assignment 65; Review OWA and Operator Challenges for Change to C4 Reference
11/04/02 PHC Meeting Minutes, January 31, 2003
CR 151097; Reactivity Management Concerns with VCT Makeup, March 27, 2003
CR 136545; Unable to Monitor Dilutions/Borations, December 18, 2002
First Quarter 2003 Operator Work Around Aggregate Impact Assessment, April 16, 2003
AR 119978; OC 254-Heater Drain Temperature Sensitivity, Assignment 08
AR 119978; OC 265-HD046A/B Oscillations, Assignment 12
CR 145948; “C4" Code Removed from WO and Work Rescheduled, February 21, 2003

1R19 Post Maintenance Testing

Technical Specifications
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Updated Final Safety Analysis Report
Schematic Diagram Containment Spray Pumps 2A & 2B Sump Suction Valves 2CS009A&B, Revision E
Diagram of Safety Injection-M-136-Sheet Number 4, Revision AP
Byron-Unit 2 Diagram of Containment Spray, M-129-Sheet Number 1B, Revision AJ
CR 157442; 1TIC;DG247B Has a Broken Probe Shield, May 6, 2003
CR 157632 DG Jacket Water HX Floating Channels Different Between U1/2, May 7, 2003
CR 157706; Relief Valves Lift During Transfer of Fuel Oil, May 5, 2003
CR 157727; Failed Agastat Relays in 1PL08J
CR 157927; 1B EDG 9L Cylinder Exhaust Valve Crosshead Fails to Return, May 8, 2003
CR 157863; Thickness Exam of Visually Identified Areas in 1DO02TB Tank, May 7, 2003
CR 158273; 1B DG Air Valves Left Out of Position, May 12, 2003
CR 158708; Difference Between 1BOSR DG-3 and Plant Label, May 14, 2003 [1]
CR 157727; Failed Agastat Relays in 1PL08J, May 5, 2003
CR 159259; Possibility of Inaccurate Level Indication, May 15, 2003
CR 162697; 2SX2082D Stem Twisted - Valve hard to Determine, June 10, 2003
ASME Code XI Oma-1988; Inservice Testing of Valves in Light Water Reactor Power Plants, Part 10
WO 543389; 1B Auxiliary Feedwater Pump Quarterly Surveillance (Both VC TRNS Must Be Available), May 16, 2003
WO 396026; 1D0020B IST Relief Valve Test, May 14, 2003
1BOSR DG-3; Unit 1 Diesel Generator Relay Operation Verification, Revision 0
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WO 402411; Perform Non-Intrusive Cleaning and Inspection, June 12, 2003
WO 402412; Perform Non-Intrusive Cleaning and Inspection, June 12, 2003
WO 402414; Perform Non-Intrusive Cleaning and Inspection, June 12, 2002
WO 432872; 1B Auxiliary Feedwater Pump Engine Driven Cooling Water Pump Discharge Check Valve, May 19, 2003
WO 470176; 2CS011B IST Disassembly and Inspection, June 10, 2003
WO 554828; 2BOSR 0.5-2.CS.1-2, STT for 2CS001B, 009B & 019B, June 10, 2003

1BVSR 4.f.2-11;Unit 1 Nonroutine Visual Examination (VT-2) of ASME Class 1, 2 and 3 Components at Nominal Operating Pressures, Revision 4
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WO 524687; Preventive Maintenance for Essential Service Cooling Tower Fan, March 17, 2003,
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1BVSR 5.5.8..1-2; Unit 1 ASME Surveillance Requirements for the Diesel-Driven Auxiliary Feedwater Pump, Revision 13
WO 524687 Task 05; Check Vibration in High Speed, May 22, 2003
WO 524687 Task 04; Run Fan in High/Low Speed for Vibration Check, May 22, 2003
OG Essential Service Water Cooling Fan Vibration Monitoring History; May 21, 2003
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NUREG 1482; Guidelines for Inservice Testing at Nuclear Power Plants, April 1995
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AR 164051; Vague Post-Maintenance Testing Instructions, June 19, 2003 [1]

1R22 Surveillance Testing

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1BOSR 8.1-2.2; Unit 1B Diesel Generator Operability Surveillance, Revision 12
WO 517363; 1B Diesel Generator Operability Semi-Annual Surveillance, May 12, 2003
Performance Trend Data for 2CS001B; August 2001 to March 2003
Votes Test Results Summary; Valve 2CS001B, June 10, 2003
Votes Test Results Summary; Valve 2CS001B, November 9, 1994
1BOSR 3.2.3-1; Unit One Undervoltage Simulated Start of 1A Auxiliary Feedwater Pump Monthly Surveillance, Revision 2
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1BVSR 5.2.4-5; Unit 1 Train A, ASME Surveillance Requirements for Centrifugal Charging Pump 1A and Chemical and Volume Control System Valve Stroke Test, Revision 6
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NSP EP-AA-125-1002; R.EP.01 and EPPI.01a-c PI Summary, May 19, 2003
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<u>3PP3</u> <u>Response to Contingency Events</u>

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Security Logged Events; January 2003 through May, 2003
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LS-AA-125; Corrective Action Program Procedure; Revision 4
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Bryon Condition Reports-Security Related (Random Review); September 2003 through May 13, 2003

<u>4OA1</u> <u>Performance Indicator Verification</u>

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Operations Narrative Logs, March 2, 2003
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BCP 300-23; Reactor Coolant or Pressurizer Liquid and/or Pressurized Grab Sample, Revision 27
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CR 112862; Unit 2 Shutdown Due to 2C SG Tube Leak, June 22, 2002
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Security Event Reports; May 2002 through April 2003

4OA3 Event Followup (71153)

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LER 454/2003-02-00, “Two Main Steam Safety Valves Lift Setpoints Found Out of Tolerance During Testing Due to Unknown Causes”, April 14, 2003
CR 141542; Operability of the Control Room Radiation Monitors, January 27, 2003
EC 342530; Determine if Control Room Ventilation System Safety Function was Lost Due to Inoperable Intake Radiation Detectors at Byron and Braidwood Stations, Revision 0
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Calculation Number CN-CRA-00-17; Byron/Braidwood Large Break LOCA Doses, Revision 1
NF-MW:03–156; Control Room Dose Estimate for the Locked Rotor with Failed PORV Event, April 25, 2003
Design Analysis Number CN-CRA-00-44; Byron/Braidwood Locked RCP Rotor with PORV Failure Accident Doses, Revision 1
MSSV Test Data; Previous Test “as left” Valves, February 16, 2003
CR 144797; 1mS015B MS Safety Valve Found out of “as found” Tolerance, February 16, 2003
Engineering Change Notice P-639; Delete Safety Injection Signal from Miscellaneous Ventilation System Control Room Office HVAC, August 21, 1986
TapRoot Root Cause Tree; Steam Generator FME Root Cause
Barrier Analysis; Steam Generator Foreign Material Exclusion Root Cause

[1] NRC Identified

LIST OF ACRONYMS USED

ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
BAP	Byron Administrative Procedure
BEP	Byron Emergency Procedure
BOP	Byron Operating Procedure
BOSR	Byron Operating Surveillance Requirement Procedure
BTP	Branch Technical Position
BVSR	Byron Technical Surveillance Requirement Procedure
CFR	Code of Federal Regulations
CR	Condition Report
DEI	Dose Equivalent Iodine
DG	Diesel Generator
ECCS	Emergency Core Cooling System
FME	Foreign Material Exclusion
HVAC	Heating, Ventilation and Air Conditioning
ICMs	Interim Compensatory Measures
IMC	Inspection Manual Chapter
MSSV	Main Steam Safety Valve
NCV	Non-Cited Violation
NRC	United States Nuclear Regulatory Commission
ODCM	Offsite dose Calculation Manual
PI	Performance Indicators
PORV	Power Operated Relief Valve
PSB	Power Systems Branch
REMP	Radiological Environmental Monitoring Program
RP	Radiation Protection
SDP	Significance Determination Process
SG	Steam Generator
SVAG	Spurious Valve Actuation Group
SX	Essential Service Water
TLD	Thermoluminescent Dosimeter
TRM	Technical Requirements Manual
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
VC	Control Room Heating Ventilation and Air Conditioning System
WO	Work Order
WR	Work Request