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

August 14, 2008

EA-08-197

Mr. Charles G. Pardee
Chief Nuclear Officer and
Senior Vice President
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BYRON STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000454/2008-003 05000455/2008-003 PRELIMINARY WHITE FINDING

Dear Mr. Pardee:

On June 30, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Byron Station, Units 1 and 2. The enclosed report documents the inspection findings, which were discussed on July 10, 2008, with Mr. D. Hoots and other members of your staff.

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

The enclosed inspection report discusses a finding that appears to have low to moderate safety significance. As documented in Section 1R13 of this report, the licensee inadvertently entered an elevated risk condition for Unit 2 in April 2008. At that time, the two Unit 1 essential service water train cross-tie isolation valves were out of service for maintenance. These two valves were opened locally to support the Unit 1 Train A emergency diesel generator testing and could not to be closed from the main control room. The licensee later determined that this configuration represented an elevated risk condition for Unit 2 due to degraded internal flood mitigation capability.

This finding was assessed based on the best available information, including influential assumptions, using the applicable significance determination process (SDP) and was preliminarily determined to be of low to moderate safety significance (White) for Unit 2 and of very low safety significance (Green) for Unit 1. The safety significance of the finding was determined assuming a Unit 1 essential service water pipe break in the auxiliary building that is not isolated due to unavailability of the two Unit 1 train cross-tie isolation valves and an exposure time of 38 hours. The final resolution of this finding will convey the increment in the importance to safety by assigning the corresponding color i.e. (White), a finding with some increased importance to safety, which may require additional NRC inspection.

This finding was not an immediate safety concern because upon identification Byron Station took immediate actions to assign a dedicated operator to locally close the valves when necessary and to restore the remote actuation capability from the main control room. You have also entered the issue into your corrective action program (CAP).

Based on the results of this inspection, one apparent violation was identified for Unit 2 and is being considered for escalated enforcement action in accordance with the NRC Enforcement Policy. The current Enforcement Policy is included on the NRC's Web site at http://www.nrc.gov/reading-rm/adams.html.

In accordance with Inspection Manual Chapter (IMC) 0609, we intend to complete our evaluation using the best available information and issue our final determination of safety significance within 90 days of this letter.

The significant determination process encourages an open dialog between the staff and the licensee, however the dialogue should not impact the timeliness of the staff's final determination. Before the NRC makes its enforcement decision, we are providing you an opportunity to either: (1) present to the NRC your perspectives on the facts and assumptions, used by the NRC to arrive at the finding and its significance at a Regulatory Conference or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 30 days of the receipt of this letter and we encourage you to submit supporting documentation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a conference is held, it will be open for public observation. The NRC will also issue a press release to announce the conference. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of the receipt of this letter. If you decline to request a Regulatory Conference or to submit a written response, your ability to appeal the final SDP determination can be affected, in that by not doing either you fail to meet the appeal requirements stated in the Prerequisite and Limitation sections of Attachment 2 of IMC 0609.

Please contact Richard Skokowski at 630-829-9620 within 10 days of the date of this letter to notify the NRC of your intended response. If an adequate response is not received within the time specified or an extension of time has not been granted by the NRC, the NRC will proceed with its enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for these inspection findings at this time. Please be advised that the number and characterization of apparent violations described in the enclosed inspection report may change as a result of further NRC review. You will be advised by separate correspondence of the results of our deliberations on this matter. Since the finding for Unit 1 is of very low safety significance, it is being treated as a Licensee Identified Non-Cited Violation in this report.

In addition, three NRC-identified and one self-revealed findings of very low safety significance (Green) were also documented in the enclosed inspection report. All four findings were determined to involve violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your CAP, the NRC is treating the issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC Enforcement Policy. Furthermore, three licensee identified violations are listed in Section 4OA7 of this report.

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, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Byron Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room). To the extent possible, you response should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the Public without redaction.

Sincerely,

/RA/

Cynthia D. Pederson, Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000454/2008-003; 05000455/2008-003
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - Byron Station
Plant Manager - Byron Station
Regulatory Assurance Manager - Byron Station
Chief Operating Officer and Senior Vice President
Senior Vice President - Midwest Operations
Senior Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Director - Licensing and Regulatory Affairs
Manager Licensing - Braidwood, Byron, and LaSalle
Associate General Counsel
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Assistant Attorney General
Illinois Emergency Management Agency
J. Klinger, State Liaison Officer,
Illinois Emergency Management Agency
P. Schmidt, State Liaison Officer, State of Wisconsin
Chairman, Illinois Commerce Commission
B. Quigley, Byron Station

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Plant Manager - Byron Station
Regulatory Assurance Manager - Byron Station
Chief Operating Officer and Senior Vice President
Senior Vice President - Midwest Operations
Senior Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Director - Licensing and Regulatory Affairs
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Illinois Emergency Management Agency
P. Schmidt, State Liaison Officer, State of Wisconsin
Chairman, Illinois Commerce Commission
B. Quigley, Byron Station

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Letter to C. Pardee from Cynthia Pederson dated August 14, 2008

SUBJECT: BYRON STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000454/2008-003 05000455/2008-003 PRELIMINARY WHITE FINDING

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-454; 50-455
License Nos:	NPF-37; NPF-66
Report Nos:	05000454/2008003 and 05000455/2008003
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	Byron, Illinois
Dates:	April 01, 2008, through June 30, 2008
Inspectors:	B. Bartlett, Senior Resident Inspector R. Ng, Resident Inspector C. Acosta, Reactor Inspector T. Bilik, Reactor Inspector J. Cassidy, Senior Health Physicist N. Féliz Adorno, Reactor Engineer J. Jacobson, Senior Reactor Inspector R. Jickling, Senior Emergency Preparedness Analyst D. Jones, Reactor Inspector V. Meghani, Reactor Inspector R. Russell, Emergency Preparedness Analyst C. Zoia, Project Engineer C. Thompson, Resident Inspector, Illinois Department of Emergency Management
Approved by:	R. Skokowski, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000454/2008-003; 05000454/2008-003; April 01 2008 – June 30, 2008; Byron Station, Units 1 and 2; Fire Protection, Inservice Inspection Activities, Maintenance Effectiveness and Maintenance Risk Assessments and Emergent Work Control.

This report covers a three-month period of inspection by resident inspectors and an announced baseline inspections by six regional inspectors. Four Green findings were identified by the inspectors. These findings were considered Non-Cited Violations (NCVs) of Nuclear Regulatory Commission (NRC) regulations. In addition, one apparent violation with potential safety significance greater than green was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a finding of very low safety significance and associated NCV of the Byron Unit 1 Operating License (OL), Condition 2.C.(6) for failure to comply with the spacing standard for sprinkler systems of the Fire Protection Program (FPP). Specifically, a permanent scaffold obstructed a fire protection suppression sprinkler in the Unit 1, train "A" (1A) diesel oil storage rank room and no replacement sprinkler was installed. The licensee entered the issue into the corrective action program (CAP) and subsequently removed the scaffold decking.

  This finding is more than minor because it was associated with the external factor attribute of the Initiating Events (IE) cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The finding is of very low safety significance because it has a low degradation rating as only one out of eleven sprinklers in the room was obstructed and there was another functional head within 10 feet of the combustible concern. This finding has a cross-cutting aspect in the area of Human Performance for Work Practices (H.4.(b)) because the licensee failed to define and effectively communicate expectations regarding procedural compliance and personnel following procedures. (Section 1R05.1.b)

- Green. The inspectors identified a finding of very low safety significance and associated NCV of Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, Section 50.55a, for the failure to correctly disposition an ultrasonic (UT) examination indication found in feedwater weld 1FW87CA-6″/C08A as required by American Society of Mechanical Engineers (ASME) Code, Section XI. This issue was entered into the licensee's CAP; the indication was re-examined and correctly dispositioned.

  The inspectors concluded that the finding was more than minor because a failure to perform the required corrective action could have allowed an unacceptable flaw to remain in service and so could become a more significant safety concern. The inspectors applied the IMC 0609, Attachment 0609.04, “Phase 1 – Initial Screening and Characterization of Findings” to this finding. The inspectors concluded that the finding was of very low safety significance, because the licensee re-performed the UT examination, and correctly dispositioned the indication in accordance with ASME Code. Furthermore, the finding did not contribute to both the likelihood of a reactor trip, and the likelihood that mitigation equipment will not be available. The inspectors determined that this finding was related to the Decision Making Component (H.1(b)) for the cross-cutting area of Human Performance. (Section 1R08.1.b)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and associated NCV of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” regarding the licensee’s failure to perform adequate evaluations of the boric acid leakage from bolted connections in accordance with Procedure ER-AP-331-1002, “Boric Acid Corrosion Control Program Identification, Screening, and Evaluations.” This issue was entered into the licensee’s CAP. Licensee corrective actions included revising the procedure and re-performing the evaluation.

  As implied by Example 4a of IMC 0612, “Power Reactor Inspection Reports,” Appendix E, “Examples of Minor Issues,” the finding was not minor under the category of “Insignificant Procedural Errors,” because the licensee routinely failed to perform/document engineering evaluations for bolted connections with boric acid leaks. A failure to adequately perform the required evaluation could result in equipment susceptible to the corrosive effects of boric acid being returned to service in a degraded condition and so could become a more significant safety concern.

  The inspectors applied the IMC 0609, Attachment 0609.04, to this finding. The inspectors checked the Reactivity Control Degraded box in the Mitigation System Cornerstone column of Table 2, and answered “no” to all of the questions in the Mitigation System Cornerstone column of Table 4a, to conclude that the finding was of very low safety significance (Green). Specifically, the finding did not represent a loss of any safety function. The inspectors determined that this finding was related to the cross-cutting component of Human Performance for Work Practices (H.4.(b)). (Section 1R08.3.b)

- Green. A finding of very low safety significance and associated NCV of Technical Specification (TS) 5.4, “Procedures,” was self-revealed on May 27, 2008, when the 0B essential service water (SX) system makeup pump failed to start during a planned monthly surveillance test. The pump failed to start due to a lack of fuel prime. The licensee determined that on April 29, 2008, the check valve on the fuel oil supply line between the day tank and the engine had been replaced as part of a routine preventive maintenance program. The check valve was found in the installed condition with a loose fitting. The loose fitting had leaked slowly allowing fuel oil to drain from the primed fuel oil supply line. The issue has been entered into the licensee’s CAP (IR 779699). The licensee’s corrective actions included repairing the check valve and associated deficiencies, as well as revising the maintenance procedure.

  The finding was considered more than minor because there was an actual loss of safety function of a single train for greater than its TS allowed outage time. The finding was determined to be of very low safety significance during a Phase 3 SDP. The primary cause of this finding was related to the cross-cutting area of Human Performance for Work Practices (H.4(c)) because licensee supervisory oversight of work activity failed to ensure procedural compliance. (Section 1R12.1.b)

- AV. The licensee identified an apparent violation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," (a)(4) for failure to perform an updated risk evaluation prior to surveillance testing of the Unit 1 Train A emergency diesel generator (EDG) based on existing plant conditions. This failure resulted in an inadvertent entry into an elevated online risk condition for Unit 2. This issue has potential safety significance greater than very low safety significance for Unit 2, which may change pending completion of the SDP. This issue was entered into their corrective action program as IR 759945. The licensee immediately implemented the compensatory measure of an operator stationed at the valve. They also took corrective actions to reassemble the valves and place them back in service.

  The finding is more than minor in accordance with IMC 0612, Appendix E, Section 7, Example f, because the elevated overall plant risk when correctly accessed, is greater than 1.0E-6 Incremental Core Damage Probability (ICDP) and also put the plant into a higher risk category with additional risk management actions. The cause of this finding was related to the cross-cutting element of human performance for work control (H.3.(b)). (Section 1R13.1.b)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 was in a refueling outage at the start of this inspection period. Initial criticality following the refueling outage was on April 14, 2008, and the unit returned to full power on April 22, 2008, after fuel pre-conditioning. The unit remained at or near full power throughout the rest of the inspection period with minor exceptions for testing.

Unit 2 operated at or near full power throughout the inspection period with minor exceptions. On May 8, 2008, power was reduced to 87 percent for turbine valve testing.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate Alternating Current (AC) Power Systems

a. Inspection Scope

The inspectors verified that plant features and procedures for operation and continued availability of offsite and alternate AC power systems during adverse weather were appropriate. The inspectors reviewed the licensee's procedures affecting these areas and the communications protocols between the transmission system operator (TSO) and the plant to verify that the appropriate information was being exchanged when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

- The coordination between the TSO and the plant during off-normal or emergency events;
- The explanations for the events;
- The estimates of when the offsite power system would be returned to a normal state; and
- The notifications from the TSO to the plant when the offsite power system was returned to normal.

The inspectors also verified that plant procedures addressed measures to monitor and maintain availability and reliability of both the offsite AC power system and the onsite alternate AC power system prior to or during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed the following:

- The actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply;
- The compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;

- A re-assessment of plant risk based on maintenance activities that could affect grid reliability, or the ability of the transmission system to provide offsite power; and
- The communications between the plant and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

Specific documents reviewed during this inspection are listed in the Attachment. The inspectors also reviewed Corrective Action Program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures.

This inspection constitutes one readiness of offsite and alternate AC power systems sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings of significance were identified.

.2 Summer Seasonal Readiness Preparations

a. Inspection Scope

The inspectors performed a review of the licensee's preparations for summer weather for selected systems, including conditions that could lead to an extended drought as a result of high temperatures.

During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. Specific documents reviewed during this inspection are listed in the Attachment. The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- Essential Service Water (SX) System Ultimate Heat Sink (UHS);
- Auxiliary Building Ventilation System; and
- Auxiliary Transformers

This inspection constitutes one seasonal adverse weather sample as defined in IP 71111.01-05.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- Spent Fuel Pool Cooling following Unit 1 Core Off-Load;
- Unit 1 Train A Diesel Generator while Unit 1 Train B Diesel Generator was Out of Service (OOS);
- Unit 1 Train B Safety Injection while Unit 1 Train A Safety Injection was OOS;
- Unit 2 Train A Residual Heat Removal (RHR) System while Unit 2 Train B RHR System was OOS; and
- Unit 2 Train B RHR while Unit 2 Train A RHR was OOS.

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

These activities constituted five partial system walkdown samples as defined by IP 71111.04-05.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On April 9, 2008, through April 10, 2008, the inspectors performed a complete system alignment inspection of Control Room Ventilation to verify the functional capability of the system. This system was selected because it was considered safety-significant. The inspectors walked down the system to review mechanical and electrical equipment line ups, electrical power availability, system pressure and temperature indications as appropriate, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding work requests was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. The documents used for the walkdown and issue review are listed in the Attachment.

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

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Unit 1 Diesel Oil Storage Tank Rooms (Zone 10.1-1 & 10.2-1);
- Unit 2 Diesel Oil Storage Tank Rooms (Zone 10.1-2 & 10.2-2);
- Fuel Handling Building (Zone 12.1-0); and
- River Screen House Including SX Makeup Pumps (Zones 18.11-0, 1 and 2).

The inspectors reviewed areas to assess if the licensee had implemented a Fire Protection Program (FPP) that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and had implemented adequate compensatory measures for out of service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the Attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed, that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP.

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

b. Findings

(1) Fire Suppression Sprinkler Obstruction in the Diesel Oil Storage Tank Room

Introduction: A finding of very low safety significance and associated non-cited violation (NCV) of the Byron Unit 1 Operating License (OL) Condition 2.C(6) for the licensee's failure to comply with the spacing standard for sprinkler systems of the Fire Protection Program (FPP) was identified by the inspectors. Specifically, a permanent scaffold obstructed a fire protection suppression sprinkler in the 1A diesel oil storage rank room and no replacement sprinkler was installed.

Description: On April 30, 2008, the inspectors performed a fire protection walkdown of the 1A diesel oil storage tank room. The inspectors identified that a permanent scaffold with solid decking material was erected underneath a fire suppression sprinkler and next to a working platform. This permanent scaffold, in conjunction with the working platform, created a deck area below the sprinkler that was 8 feet 9 inches in the north-south direction and 6 feet 5 inches in the east-west direction. Since this area was irregular shaped, the shortest dimension was 4 feet 4 inches in the southwest diagonal direction. The combination of the permanent scaffold and the working platform obstructed a major portion of the spray pattern of one of the foam based fire suppression sprinklers to a portion of the floor area in the diesel oil storage tank room. No sprinkler was installed to supplement the one that had been obstructed. The 1A diesel oil storage tank room houses two diesel oil storage tanks that contain the diesel fuel oil used by the 1A emergency diesel generator (EDG) and 1A diesel driven auxiliary feedwater (AFW) pump.

The licensee declared the fire suppression system for the 1A diesel oil storage tank room inoperable and verified that the automatic fire detection instrumentation was operable in accordance with the Technical Requirement Manual (TRM). The licensee subsequently removed the decking of the permanent scaffold.

The inspectors reviewed that the Permanent Scaffold Request B-4855 and determined that the permanent scaffold had been inspected, evaluated and approved by engineering personnel in March 2004. However, the procedure in effect at the time of the scaffold erection, MA-AA-716-025, "Scaffold Installation, Modification, and Removal Request Process," Revision 0, required that engineering review and evaluate the technical impact of the proposed permanent scaffold and approve post erection inspections as needed. One of the evaluation criteria specified by the procedure was to determine if the scaffold would affect the coverage zone of any in-place fire protection sprinkler heads in the immediate proximity. No specific concern or instruction was noted when the scaffold request was approved by engineering.

The inspectors determined that the licensee was committed to National Fire Protection Association (NFPA) Code 13, "Standard for the Installation of Sprinkler Systems," 1983 Edition, and NFPA Code 16, Deluge Foam Water Sprinkler and Sprays Systems, 1980 Edition, according to the licensee's Fire Protection Report. Per these standards, sprinklers shall be installed under decks which are over four feet wide to prevent obstruction for the spray pattern of the sprinkler. Specifically, Section 4-2.1 of NFPA-16 stated that foam-water sprinkler system designs shall conform to all of the applicable requirements of NFPA-13 except where otherwise specified in NFPA-16. Section 4-4.11 of NFPA-13 specified that sprinklers be installed under decks and galleries which are over four feet wide. As NFPA-16 did not specifically address sprinkler obstructions, the requirements of NFPA-13 pertaining to obstructions applied.

Analysis: The inspectors determined that the licensee's failure to comply with the spacing standard for sprinkler systems in accordance with the FPP was a performance deficiency that warranted a IMC 0609, "Significance Determination Process" (SDP) evaluation. The inspector concluded that the finding was greater than minor in accordance with IMC 0612, Appendix B, "Issue Disposition Screening." Specifically, it was associated with the external factor attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, Appendix F, "Fire Protection Significance Determination Process", because it was associated with fire protection defense-in-depth strategies involving suppression system. The inspectors determined that the finding has a low degradation rating since only one out of eleven sprinklers in the room was obstructed and there was another functional head within ten feet of the combustible concern. In addition, other aspects of the system complied with NFPA code. Therefore the finding was determined to be of very low safety significance (Green).

This finding has a cross-cutting aspect in the area of Human Performance for Work Practices (H.4.(b)) because the licensee failed to define and effectively communicate expectations regarding procedural compliance and personnel following procedures.

Enforcement: Byron Unit 1 OL, Condition 2.C.(6) states, in part, that the licensee shall implement and maintain in effect all provisions of the approved FPP as described in the licensee's Fire Protection Report. The Fire Protection Report stated that the licensee's sprinkler system conformed to NFPA Code 13, 1983, edition, and no deviation applied to this fire area. Per the NFPA standard, sprinklers shall be installed under decks that are over four feet wide. Contrary to the above, a permanent scaffold was erected in conjunction with an existing platform structure, creating a deck area that was 4 feet 4 inches in the diagonal direction. This permanent scaffold, in conjunction with the working platform, obstructed a fire suppression sprinkler and no sprinkler was installed to supplement the obstructed one. Because this violation was of very low safety significance and because it was entered into the licensee's CAP as Issue Report (IR) 770364, this violation is being treated as a NCV, consistent with Section VI.A.1 of the NRC enforcement policy. (NCV 05000454/2008003-01)

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations, and abnormal operating procedures, for licensee commitments. The specific documents reviewed are listed in the Attachment.

In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's CAP documents with respect to past flood-related items identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant area to assess the adequacy of watertight doors and to verify drains and sumps were clear of debris and operable and that the licensee complied with its commitments:

- Turbine Building Basement.

These inspection activities constitute one internal flooding sample as defined in IP 71111.06-05.

a. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08P)

From March 24, 2008, through April 3, 2008, the inspectors conducted a review of the implementation of the licensee's ISI Program for monitoring degradation of the reactor coolant system, steam generator tubes, emergency feedwater systems, risk significant piping, and components and containment systems.

The inspections described in Sections 1R08.1, 1R08.2, 1R08.3, 1R08.4, and 1R08.5 below count as one inspection sample as defined by IP 71111.08-05.

.1 Piping Systems ISI

a. Inspection Scope

The inspectors reviewed records of the following nondestructive (NDE) examinations mandated by the American Society of Mechanical Engineers (ASME) Code, Section XI to evaluate compliance with the ASME Code, Section XI and Section V, requirements and if any indications and defects were detected, to determine if these were dispositioned in accordance with the ASME Code or an NRC approved alternative requirement.

- Ultrasonic Testing (UT) examination of Steam Generator (SG) 1RC-01-BB, N-3-NIR inner radius; and
- Liquid penetrant examination of 1SI03DA-2, W-09.

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

- UT examination of RHR heat exchanger 1RH-02-AB shell to flange weld RHEC-013; and
- UT examination of feedwater weld 1FW87CA-6″/CO8A.

Review of pressure boundary welding was completed during performance of Temporary Instruction (TI)-172 as documented in Section 4OA5, and this review is credited for meeting this inspection procedure attribute.

b. Findings

(1) Failure to Correctly Evaluate and Disposition a Weld Indication

Introduction: The inspectors identified a Green NCV of 10 CFR Part 50.55a, for failure of the licensee to correctly disposition a flaw found in feedwater weld 1FW87CA-6″/C08A as required by ASME Code Section XI discovered while performing a Performance Demonstration Initiative (PDI) UT examination.

Description: During a records review of the UT examination performed on September 15, 2006, of feedwater weld 1FW87CA-6″/C08A as directed by IP 71111.08 Section 02.01(e), the inspectors observed that the licensee had failed to correctly evaluate and disposition a weld indication in accordance with ASME Code after it was identified during a PDI UT examination.

While performing a PDI UT examination of a weld of a 6″, 0.432″ nominal thickness, ferritic feedwater pipe, using 45 degree and 60 degree shear waves, the examiners identified a mid-wall indication, with an “L” max dimension of 2.0″. The indication occurred outside of the minimum required exam volume and reportedly did not have an inside diameter connection. A sketch included with the licensee’s report shows the indication to be near the fusion zone of the weld, and the indication was detected with the 60 degree search unit. While the examiners reported the indication as a recordable indication, the reviewer indicated that no further evaluation of the flaw was required. The decision to forgo further evaluation was supported by both the licensee’s UT Level III and the Authorized Nuclear Inservice Inspector. In response to the inspectors’ question as to why there was no further evaluation performed, the licensee stated that it was because the indication was not located in the minimum required weld volume they had interrogated, nor was there any guidance in the procedure for addressing indications outside of the volume they intended to examine. However, the inspectors determined that ASME evaluation requirements are not limited to just indications that are found in the minimum weld volume.

Analysis: The inspectors determined that the failure of the licensee to perform ASME Code required corrective actions for an indication found during PDI UT examination of a feedwater weld, was a performance deficiency that warranted a SDP evaluation. The inspectors compared this issue to the issues identified in Appendix E of IMC 0612 to determine whether the issue was minor, and concluded that none of the examples listed in Appendix E, accurately represented this example. As a result, the inspector compared this issue to the “minor” questions contained in Section 3, “Minor Questions,” to IMC 0612, Appendix B, “Issue Screening.” The inspectors concluded that the finding was more than minor because a failure to perform the required corrective action could have allowed an unacceptable flaw to remain in service and so could become a more significant safety concern.

The inspectors applied the IMC 0609, Attachment IMC 0609.04, to this finding. The inspectors checked the Primary System LOCA Initiator Contributor box in the Initiating Events Cornerstone column of Table 2, and answered “no” to the question in the LOCA

Initiator Cornerstone column of Table 4a, to conclude that the finding was of very low safety significance (Green).

Specifically, the licensee re-performed the UT examination and correctly dispositioned the indication in accordance with ASME Code. Furthermore, the finding did not contribute to both the likelihood of a reactor trip, and the likelihood that mitigation equipment will not be available.

The inspectors determined that this finding was related to the Decision Making Component (H.1(b)) aspect for the cross-cutting area of Human Performance, because the licensee failed to make conservative assumptions in decisions affecting the integrity of the feedwater piping. Specifically, the licensee's presumption of weld integrity was not based on sufficient information to be able to demonstrate that the action/decision to leave the feedwater piping with an unevaluated piping weld indication in service was safe.

Enforcement: Between March 24, 2008, and April 3, 2008, while performing baseline IP 71111.08, the inspectors identified a NCV of 10 CFR 50.55(a)(g)(4), in that the licensee failed to correctly disposition an indication found in feedwater weld 1FW87CA-6″/C08A, as required by ASME Code Section XI, discovered while performing a PDI UT examination.

Title 10 CFR 50.55(a)(g)(4), required, in part, that pressurized water-cooled nuclear power facility components classified as ASME Class 1, Class 2, and Class 3 meet the requirements set forth in ASME Code Section XI. ASME Code, Section XI, IWB-3131(c), required in part, that acceptance of components for continued service shall be in accordance with Tables IWB-3132, IWB-3133, and IWB - 3134. IWB-3132.1, stated in part, that a component that does not meet the acceptance standards of Table IWB-3410-1 shall be corrected in accordance with the provisions of IWB-3132.2 (Acceptance by Repair/Replacement) or IWB-3132.3 (Acceptance by Analytical Evaluation).

Contrary to the above, on September 15, 2006, during B1R14, after identifying a UT indication in feedwater weld 1FW87CA-6″/C08A, which did not meet the acceptance standards of Table IWB-3410-1 (identified in report number B1R14-UT-027), the licensee failed to disposition by repair, replacement, or acceptance by evaluation as required by the ASME Code prior to returning Unit 1 to service.

Because of the very low safety significance of this finding and because the issue was entered into the licensee's CAP (IR 756048), it is being treated as a NCV, consistent with Section VI.A.1, of the NRC Enforcement Policy (NCV 05000454/2008003-02).

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

The inspectors reviewed a video recording of the visual examinations conducted on the Unit 1 reactor vessel head to determine if the activities were performed in accordance with the requirements of NRC Order EA-03-009, and if any indications and defects were detected, to determine if these were dispositioned in accordance with the ASME Code or an NRC approved alternative requirement. The inspectors also reviewed the vessel head visual examination procedure to determine if criteria existed for visual examination quality and if instructions existed for resolving interference or masking issues.

The licensee did not perform any weld repairs to vessel head penetrations since the beginning of the preceding outage for Unit 1. Therefore, no NRC review was completed for this IP attribute.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control (BACC)

a. Inspection Scope

The inspectors observed the licensee BACC visual examinations for portions of the Reactor Coolant System (RCS) to determine if these visual examinations emphasized locations where boric acid leaks can cause degradation of safety significant components.

The inspectors reviewed the following engineering evaluations of reactor coolant system components with boric acid deposits to determine if degraded components were properly documented in the CAP. The inspectors also evaluated corrective actions for any degraded RCS components to determine if they met the ASME Code, Section XI, or NRC approved alternative.

- IR 650150; 1CV066A Pipe Cap Leak (Boric Acid)-Valve Leak By Issue;
- IR 563581; 1CV8524B Body to Bonnet Leakage; and
- IR 641851; 1SI8812B Inactive Body-to Bonnet Leak.

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

- IR 640441; Damp Boric Acid Present on 1AB03T Tank FLG'D Tap; and
- IR 616011; 2RH8702A Active Body to Bonnet Leak.

b. Findings

(1) Failure to Perform Evaluation of a Leaking Bolted Connection

Introduction: The inspectors identified a Green NCV of 10 CFR Part 50, Appendix B, Criterion V, regarding the licensee's failure to perform adequate evaluations of the boric acid leakage from bolted connections in accordance with the procedure ER-AP-331-1002, "Boric Acid Corrosion Control Program Identification, Screening, and Evaluations." Specifically, in the evaluations of the boric acid leaks documented in IR 641851 and IR 563581, the licensee did not adequately address all applicable considerations per ER-AP-331-1002, Attachment 3, "Evaluation of Leakage from Bolted Connection," Section 7.

Description: ASME Code, Section XI (2001, through 2003 Addenda), IWA-5250(a)(2), requires removal and VT-3 examination of the bolts as corrective action, when a leak occurs at a bolted connection in a borated system. Code Case N-566-2, “Corrective Action for Leakage Identified at Bolted Connections,” provides for evaluation as an alternative to removal of the bolts. The Code Case was approved by the NRC on March 28, 2001, and is included in the Licensee’s ISI Program Plan. The Code Case specifies the parameters to be included in the evaluation. The licensee has incorporated these parameters in Attachment 3, of the Procedure ER−AP−331-1002.

During inspections performed between March 24, 2008, and April 3, 2008, the inspectors identified that the licensee had failed to adequately document evaluations of bolted connections with evidence of boric acid leakage. Specifically, in the evaluations for body-to-bonnet leaks for Valve 1SI8812B documented in IR 563581 on November 30, 2006, and Valve 1CV8524B documented in IR 563581 on February 1, 2007, the licensee concluded that it was not necessary to remove the bolts for further examination without adequately addressing in the evaluation all the parameters specified in Code Case N-566-2. The licensee used Attachment 3, of Procedure ER-AP-331-1002, to document the evaluation. Section 7 of the Attachment lists all the parameters included in the Code Case and required their consideration in the evaluation. The inspectors however, were not able to verify through review of licensee’s documentation that all the parameters were considered in the evaluation, which based its conclusion of acceptability on the material being stainless steel, not susceptible to boric acid corrosion. The inspectors found similar instances in other boric acid evaluations including some where the affected bolt material was carbon steel and therefore concluded that adequate evaluations were not being performed prior to documenting the conclusions. After identification by the inspector, the licensee documented the issue in their CAP as IR 755998, “Inadequate Boric Acid Evaluations of Mechanical Joints,” dated March 3, 2008. The licensee’s corrective actions involved revising the procedure and then re-performing the evaluations.

Analysis: The inspectors determined that the failure of the licensee to perform adequate evaluation of bolted connections with evidence of leakage as required by the Code Case N-566-2 and their procedure was a performance deficiency that warranted a significance evaluation. The inspectors believed that for the evaluations reviewed, based on the amount of leakage and degradation documented, the conclusion of the evaluation would not have changed had an adequate evaluation been performed. However, as implied by Example 4a of IMC 0612, Appendix E, the finding was not minor under the category of “Insignificant Procedural Errors,” because the licensee routinely failed to perform/document engineering evaluations for bolted connections with boric acid leaks. The finding was also more than minor because a failure to adequately perform the required evaluation could result in equipment susceptible to the corrosive effects of boric acid being returned to service in a degraded condition and thus become a more significant safety concern.

The inspectors applied the IMC 0609, Attachment 0609.04, to this finding. The inspectors checked the Reactivity Control Degraded box in the Mitigation System Cornerstone column of Table 2, and answered “no” to all of the questions in the Mitigation System Cornerstone column of Table 4a, to conclude that the finding was of very low safety significance (Green). Specifically, the finding did not represent a loss of any safety function.

This finding was related to the cross-cutting component of Human Performance for Work Practices (H.4.(b)) in that, the licensee failed to define and effectively communicate expectations regarding procedural compliance. Specifically, the licensee repeatedly failed to adequately perform/document the evaluations required per Attachment 3, Section 7 of the ER-AP-331-1002, Revision 3.

Enforcement: During inspections performed between March 24, 2008, and April 3, 2008, the inspectors identified a NCV of 10 CFR Part 50, Appendix B, Criterion V, in that the licensee failed to perform engineering evaluations on bolted connections with evidence of leakage in accordance with their procedure.

Title 10 CFR Part 50, Appendix B, Criterion V, requires in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances, and shall be accomplished in accordance with these instructions, procedures, or drawings.

License Procedure ER-AP-331-1002, Revision 3, Attachment 3, Section 7 lists the parameters/attributes that must be considered in the evaluation.

Contrary to the above, on August 20, 2007, for Valve 1SI8812B, and on January 31, 2007, for Valve 1CV8524B, the licensee failed to perform adequate evaluations in accordance with Procedure ER-AP-331-1002, Revision 3. Specifically, in the evaluations for leakage from bolted connections discovered per IR 641851 and IR 563581, the licensee staff failed to perform/document evaluations considering all the parameters/attributes specified in the Attachment 3, Section 7 of ER-AP-331-1002. Because of the very low safety significance of this finding and because the issue was entered into the licensee's CAP (IR 755998), it is being treated as a NCV, consistent with Section VI.A.1 of the Enforcement Policy (NCV 05000454/2008003-03).

.4 SG Tube Inspection Activities

a. Inspection Scope

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

- in-situ SG tube pressure testing screening criteria used were consistent with those identified in the Electric Power Research Institute (EPRI) TR-107620, Steam Generator In-Situ Pressure Test Guidelines and that these criteria were properly applied to screen degraded SG tubes for in-situ pressure testing;
- the numbers and sizes of SG tube flaws/degradation identified was bound by the licensee's previous outage Operational Assessment predictions;
- the numbers and sizes of SG tube flaws/degradation identified was bound by the licensee's previous outage Operational Assessment predictions;
- the SG tube ET examination scope and expansion criteria were sufficient to meet the Technical Specifications, and the EPRI 1003138, Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6;
- the SG tube ET examination scope included potential areas of tube degradation identified in prior outage SG tube inspections and/or as identified in NRC generic industry operating experience applicable to these SG tubes;

- the licensee identified new tube degradation mechanisms and implemented adequate extent of condition inspection scope and repairs for the new tube degradation mechanism;
- the licensee implemented repair methods which were consistent with the repair processes allowed in the plant TS requirements and to determine if qualified depth sizing methods were applied to degraded tubes accepted for continued service;
- the licensee implemented an inappropriate "plug on detection" tube repair threshold (e.g., no attempt at sizing of flaws to confirm tube integrity);
- the licensee primary-to-secondary leakage (e.g., SG tube leakage) was below 3 gallons-per-day or the detection threshold during the previous operating cycle; the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, Performance Demonstration for Eddy Current Examination, of EPRI 1003138, Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 6;
- the licensee performed secondary side SG inspections for location and removal of foreign materials; and
- inaccessible foreign objects were left within the secondary side of the SGs, and if so, that the licensee implemented evaluations which included the effects of foreign object migration and/or tube fretting damage.

The licensee did not perform in-situ pressure testing of SG tubes. Therefore, no NRC review was completed for this inspection attribute.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI/SG related problems entered into the licensee's CAP and conducted interviews with licensee staff to determine if;

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

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

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On June 3, 2008, the inspectors observed a crew of licensed operators in the plant simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements.

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

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- Station Auxiliary Transformer 242-2 Differential Overcurrent Trip; and
- Essential Service Water Makeup Pump 0B Failure to Start on Demand.

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

- implementing appropriate work practices;
- identifying and addressing common cause failures;

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

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

This inspection constitutes two quarterly maintenance effectiveness samples as defined in IP 71111.12-05.

b. Findings

(1) Essential Service Water Makeup Pump 0B Failure to Start on Demand

Introduction: A finding of very low safety significance and an NCV of TS 5.4 was self-revealed on May 27, 2008, when the 0B SX Makeup pump failed to start during a planned monthly surveillance test. The pump failed to start due to a lack of fuel prime.

Description: On May 27, 2008, a routine monthly surveillance was initiated on the 0B SX Makeup pump. The pump failed to start and troubleshooting was initiated. The diesel portion of the pump was determined to have lost fuel oil prime in the fuel line from the day tank to the engine. In addition, a loose fitting allowed air to be drawn into the line resulting in an inability to prime the line.

The licensee determined that on April 29, 2008, the check valve on the fuel oil supply line between the day tank and the engine had been replaced as part of a routine preventive maintenance program. The check valve was found in the installed condition with a loose fitting. The loose fitting had leaked slowly allowing fuel oil to drain from the primed fuel oil supply line. This leak had also allowed air to enter the line when the engine driven fuel pump operated during the start attempt. The fuel oil line has a sight glass that allows operators, during their daily rounds, to check to ensure the line has remained full of fuel. The licensee determined that following the maintenance in April that the sight glass had been left with a slight down slope. This allowed fuel to remain in the sight glass even though the fuel oil line it was attached to had drained. This slope was not significant enough to be noticed by the operators.

Work Order (WO) 912183, "Replace Parker check valve at SX Makeup pump fuel oil line," was utilized by the workers when replacing the check valve. Document 1 of the work package instructions required, "Install new check valve using approved thread sealant and tighten fittings in accordance with Parker Tightening Instructions…." The licensee determined that the fitting was loose when installed and did not become fully tightened during assembly.

Technical Specification 3.7.9, “Ultimate Heat Sink,” Condition C, required that with both units in Mode 1, 2, 3, or 4, that one inoperable SX makeup pump be restored to operable within seven days and if not to perform a unit shutdown. The pump maintenance was performed April 29, 2008, and while a precise leak rate could not be calculated as the check valve as found condition was disturbed when it was replaced it was estimated to be a small fraction of the 26 days between the maintenance activity and the discovery of the failed pump. The estimation was performed by the inspectors after discussions with licensee personnel, inspection of the check valve, inspection of the total volume of the engine fuel oil system, and estimation of the relative size of the fuel oil leak given that an in-leakage of air sufficient to prevent priming of the line was occurring.

<u>Analysis</u>: The inspectors determined that the licensee’s failure to adequately follow the work instructions was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with Appendix B of IMC 0612, because there was an actual loss of safety function of a single train for greater than its TS allowed outage time.

The inspectors performed a SDP of this issue using IMC 0609, Attachment IMC 0609.04. The inspectors determined the finding fell under the Mitigating Systems Cornerstone and that the finding did not represent a design or qualification deficiency, did not represent a loss of a safety system function, but did represent an actual loss of safety function of a single train for greater than its TS allowed outage time. The inspectors then performed a Phase 2 SDP using the risk informed inspection notebook. The Phase 2 SDP result was greater than green assuming that the unavailability of the 0B SX make-up pump increases the likelihood of a loss of essential service water event for an exposure period of between 3 and 30 days.

However, the Senior Reactor Analyst (SRA) determined that this result was overly conservative because the unavailability of the 0B SX make-up pump would not increase the likelihood of a loss of essential service water pump by an order of magnitude. A Phase 3 SDP evaluation was completed using the Simplified Plant Analysis Risk Model (SPAR) for Byron, Revision 3.31. The 0B SX make-up pump was assumed to be unavailable and not recoverable for a bounding period of 30 days. The change in core damage frequency was calculated to be 1E-7/yr, which represented a finding of very low safety significance (Green). The dominant core damage sequence was a dual unit loss of offsite power, failure of all SX makeup which in turn fails the DGs and results in a station blackout. Recovery of offsite or onsite AC power fails resulting in core damage. Therefore, the inspectors determined that the finding was of very low safety significance. The primary cause of this finding was related to the cross-cutting area of Human Performance for Work Practices (H.4.(c)) because licensee supervisory oversight of work activity failed to ensure procedural compliance.

<u>Enforcement</u>: Technical Specification 5.4 required the implementation of the applicable procedures recommended in Regulatory Guide 1.33, “Quality Assurance Program Requirements,” Revision 2, dated February 1978. Regulatory Guide 1.33, Appendix A, recommended procedures for the system. Maintenance Procedure MA-AA-716-011, “Work Execution and Close Out,” Revision 11 was written in accordance with Section 9, Performing Maintenance. Step 4.8.1.1.B required “Perform work activities and equipment checks in accordance with approved procedures or work instructions.” Contrary to this requirement, a work instruction contained within WO 912183 was not followed in that fittings were not tightened resulting in an inoperable SX makeup pump.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's CAP (IR 779699); the issue is being treated as an NCV, consistent with Section VI.A.1, of the NRC Enforcement Policy. The licensee's corrective actions included repairing the check valve and associated deficiencies, as well as revising the maintenance procedure. (NCV 05000454/2008003-04; 05000455/2008003-04)

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- Emergent Shutdown Safety Change due to Extended Work on Unit 1 Train A Charging Pump;
- Unit 1 Train A RHR Suction Drain while Unit 1 Division 11 DC Bus was OOS;
- Inadvertent Orange Risk Entry due to Both Unit 1 SX Unit Cross-tie Isolation Valves Unavailable for Remote Operation; and
- Bus 22 Battery Charger while Unit 2 System Auxiliary Transformer (SAT) and Unit 2 Train C Power Operated Relief Valves (PORVs) were OOS.

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

These activities constituted four samples as defined by IP 71111.13-05.

b. Findings

(1) Failure to Perform an Updated Risk Evaluation Prior to Surveillance Testing of the Unit 1 Train A Diesel Generator Based on Existing Plant Conditions.

Introduction: The licensee identified an apparent violation of 10 CFR 50.65(a)(4) for the licensee's failure to perform an updated risk evaluation prior to surveillance testing of the Unit 1 Train A EDG based on existing plant conditions.

Description: On March 31, 2008, Unit 1 was in a refueling outage with the head removed, cavity flooded up and defueled. The spent fuel pool was at normal level and decay heat was being removed via the component cooling exchanger to the SX system.

Unit 2 was at 100 percent power and normal operation. Online risk for Unit 2 was evaluated as Yellow assuming all planned maintenance for the week occurred at the same time. Shutdown risk for Unit 1 was Green.

The Unit 1 SX train cross-tie isolation valve (1SX034) was scheduled for replacement during the week of March 31, 2008. As part of the maintenance isolation and replacement activities, both Unit 1 SX train cross-tie isolation valves (1SX033 and 1SX034) were closed and electrically isolated. The licensee's risk assessment considered both Unit 1 train cross-tie valves closed. The valves are normally open but need to be able to close to mitigate flooding in auxiliary building due to an SX system pipe break.

The licensee began disassembling the electrical connection of the valve actuator for 1SX034 on March 31, 2008. Due to isolation issues, the scheduled replacement of 1SX034 was aborted but the electrical connection was not restored immediately. In addition, 1SX033 was observed to have an actuator problem so maintenance activities for 1SX033 commenced on April 2, 2008. Valve 1SX034 was utilized as an isolation point for the maintenance on 1SX033. A new risk assessment was performed and considered both valves "unable to open." Online risk for Unit 2 was evaluated as Yellow and shutdown risk for Unit 1 was evaluated as Green. Appropriate risk management actions were carried out for this condition.

At 12:31 on April 3, 2008, Unit 1 entered Mode 6 when the first fuel assembly was moved back into the reactor vessel. Time to boil was calculated to be 14.7 hours at the time and shutdown risk for Unit 1 was Yellow for reactivity due to fuel moves.

At 03:04 on April 5, 2008, both the 1SX033 and 1SX034 valves were fully opened to support Unit 1 Train A diesel generator testing. Remote manipulation capability of the two valves remained unavailable in the main control room since the electrical isolations remained in place. The open position is the normal operating position of both the 1SX033 and 1SX034 valves. This alignment cross-ties the SX pump supply to the A and B headers for Unit 1 and is needed for diesel generator testing. This open valve configuration was not evaluated for Unit 1 shutdown risk, nor was it evaluated for Unit 2 online risk. At the time, time to boil for Unit 1 was calculated to be 16.2 hours.

At 08:05 on April 6, 2008, core reload was completed and shutdown risk for Unit 1 returned to Green. At 13:00 on April 6, 2008, the upper internals were installed which reduced time to boil to 7.9 hours.

At about mid-morning on April 6, 2008, while developing the risk evaluation for the week of April 7, 2008, the work control cycle manager was informed by the cycle manager from the previous week that the work for the two SX cross-tie valves was carrying over to the week of April 7, 2008. The cycle manager identified the bounding cases for these valves as "1SX033/34 unable to open if closed" and 1SX033/34 unable to close if open." These bounding cases were discussed with the site risk engineer and the engineer performed a risk evaluation under those assumptions. The risk engineer determined that with both valves opened and unable to be closed from the main control room, the online risk profile for Unit 2 would be Orange. The shift manager was then contacted to confirm the configuration of the valves and the cycle manager discovered that both 1SX033 and 1SX034 were electrically de-energized and in the open position.

At 16:52 on April 6, 2008, the licensee declared the Unit 2 online risk to be Orange due to the inability to close 1SX033 and 1SX034 from the main control room to prevent flooding. Unit 1 shutdown risk remained unchanged. At 17:12 on April 6, 2008, an operator was stationed locally at 1SX033 to close the valve if necessary. The Unit 2 online risk was then returned to green. The total time the plant was in Orange risk condition was 38 hours and 8 minutes. Time to boil for Unit 1 remained at 7.9 hours at that time. The licensee immediately implemented the compensatory measure of an operator stationed at the valve. They also took corrective actions to reassemble the valves and place them back in service.

Analysis: The inspectors determined that the licensee failed to update a prior risk assessment due to changing plant conditions. Specifically, the licensee did not perform an updated risk evaluation prior to surveillance testing of the Unit 1 Train A EDG based on existing plant conditions with the 1SX033 and 1SX034 valves opened and unable to close from the main control room. This plant configuration degraded auxiliary building flooding mitigation capability during diesel generator testing. The inspectors determined this to be a performance deficiency warranting a significance evaluation.

The inspectors determined that the licensee failed to consider risk significant SSCs that were unavailable during maintenance and the issue was within the licensee's ability to foresee and correct and the condition could have been prevented.

The inspectors determined the performance deficiency was more than minor in accordance with IMC 0612, Appendix E, Section 7, Example f, because the elevated overall plant risk when correctly assessed was greater than 1.0E-6 Incremental Core Damage Probability (ICDP) and also put the plant into a higher risk category with additional risk management actions. This finding had the potential to become a more significant event if the two isolation valves were required to mitigate flooding in the auxiliary building.

IMC 0609, Appendix K, "Maintenance Risk Assessment and Risk Management Significance Determination Process," was used to determine the significance of the finding for Unit 2, which was at power during the exposure period. The inspectors requested that the licensee re-perform the 10 CFR 50.65(a)(4) assessment for the exposure period of the finding assuming that both 1SX033 and 1SX034 valves were unable to close. For Unit 2, which was operating at full power at the time, the Incremental Core Damage Frequency (ICDF) was calculated to be 7.56E-4/yr. Given that the condition existed for 38 hours, the ICDP was 3.3E-6.

Since the licensee failed to conduct an adequate risk evaluation for the maintenance activities, the ICDP is equal to the Incremental Core Damage Probability Deficit (ICDPD). No risk management actions (RMAs) were specified or taken because no risk evaluation of the actual configuration was performed. Using flowchart 1 of IMC 0609 Appendix K, a finding with an ICDPD of 3.3E-6 with no RMAs is assessed as a White finding (low to moderate safety significance).

The dominant sequence for this configuration is an Unit 1 pipe break in the auxiliary building that is not isolated due to the unavailability of the 1SX033 and 1SX034 valves. The failure of the 1SX033 and 1SX034 valves to close is assumed to result in the failure to isolate the flood. As auxiliary building flooding continues, the SX pumps for both units will be rendered inoperable resulting in a loss of all SX. Eventually an reactor coolant pump (RCP) seal LOCA will occur with no inventory makeup capability.

The finding also affected the risk for Unit 1. Since the unit was in a refueling outage, all maintenance risk assessments are qualitative; therefore the IMC 0609 Appendix K approach cannot be applied. The risk impact to Unit 1 was considered to be lower than for Unit 2 because the unit had been shutdown since March 23, 2008, decay heat load was low, and the time to boil was long. Using these qualitative risk insights, the finding is assessed to be of very low safety significance (Green) for Unit 1.

The licensee subsequently performed a risk evaluation of the condition that considered 1SX034 available through recovery efforts. In this evaluation, the licensee assumed that once flooding isolation was needed the valve would be returned to service, the breaker closed, and the valve operated as necessary from the control room with a slightly increased human error probability. The inspectors determined that the assumption that 1SX034 was recoverable was incorrect because the valve was electrically isolated and could not be operated from the control room. More specifically, workers would have to re-connect wiring and perform other maintenance actions to return the valve to service, which would not have been feasible in a potentially flooded environment.

The licensee performed another risk evaluation that credited an alternate strategy for isolating leakage from an SX pipe break in the auxiliary building. The conclusion of this evaluation was that the risk of the unavailability of the 1SX033 and 1SX034 valves was of very low safety significance (Green). The inspectors and the SRA reviewed the alternate strategy and determined that it was not appropriate to credit this strategy for the reasons described in the following paragraphs.

The alternate strategy for isolating flooding is significantly different from the success strategy credited in the licensee's Probability Risk Analysis (PRA). The PRA credits detection and isolation of the affected train by closing several motor-operated valves and shutting down the pump in the train. The strategy is directed by the use of an Abnormal Operating Procedure, 0BOA PRI-8, "Auxiliary Building Flooding." Most of the actions are performed from the control room. The alternate strategy relies on local visual identification of the pipe break and local manual actions to close valves to isolate the flood. Operators would be required to identify the specific section of pipe that failed, use drawings and other reference information to determine which valves to close, and would have to locally close valves in the auxiliary building. In some cases, the valves are normally locked open and operators would be required to obtain a key and unlock the valve before manually closing it. Since flooding would be in progress in the auxiliary building, access to equipment is not assured and local actions cannot be considered to be appropriately reliable to credit for mitigation.

The procedure guidance to implement the alternate strategy was weak. The alternate strategy requires the use of reference Procedure BOP SX-22, "Essential Service Water Leak Isolation" to specify which valves need to be closed based on the line segment of piping that is determined to be failed. It is not clear how operators would transition from abnormal operating Procedure 0BOA PRI-8 to reference Procedure BOP SX-22 based on the inability to close the train Cross-tie Isolation Valves 1SX033 and 1SX034. Abnormal Operating Procedure 0BOA PRI-8 does not have any actions in the Response Not Obtained column for the failure of 1SX033 and 1SX034. Although Abnormal Operating Procedure 0BOA PRI-8 references BOP SX-22, it is only in the system restoration section of the procedure, not in the leak isolation procedure section. It appears that reference Procedure BOP SX-22 was intended to provide guidance on specific valves to close to isolate a section of SX piping for repair and not intended to be required to stop internal flooding.

These procedures were recently implemented, and based on interviews there was limited operator familiarity. A short training session, focusing on a single flood scenario as an example, had been given to only three of five crews at the time this condition existed.

In summary, due to the complex nature of the actions required to isolate flooding if 1SX033 and 1SX034 could not be closed, the lack of adequate procedure guidance, and limited training and familiarity with leak isolation strategies, the NRC determined that the likelihood of success was low and the alternate strategy should not be credited to mitigate the risk from internal flooding if 1SX033 and 1SX034 are unavailable.

The primary cause of this issue is related to the cross-cutting area of Human Performance for Work Control (H.3.(b)), because the licensee did not appropriately coordinate work activities by incorporating actions to address the impact of 1SX033 and 1SX034 not able to be closed from control room during diesel generator testing and the need for work groups to communicate coordinate and cooperate with each others.

Enforcement: 10 CFR 50.65(a)(4) requires in part, that the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities before performing maintenance. Contrary to the above, from April 5, 2008, to April 6, 2008, the licensee failed to consider risk significant components that were unavailable in their risk evaluation before performing maintenance. Specifically, between 03:04 on April 5, 2008, and 17:12 on April 6, 2008, the licensee was at an unrecognized Orange risk condition for Byron Unit 2 when the licensee conducted the 1A EDG testing with both Unit 1 essential service water train Cross-tie Isolation Valves, 1SX033 and 1SX034, left opened and unable to be closed in the main control room. For Unit 2, this is an apparent violation of 10 CFR 50.65(a)(4) pending the completion of the final significance determination. (AV 05000455/2008003-05)

Since the licensee restored the remote operation capability of one of the two isolation valves after its discovery, the finding does not represent an immediate or current safety concern. This issue was entered into their corrective action program as IR 759945.

For Unit 1, because of the very low safety significance of the issue and because the issue has been entered into the licensee's CAP, the issue is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. Since this violation was licensee identified, the enforcement aspect is described in Section 4OA7 of this report.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Unit 2 Train A Diesel Generator Air Leak;
- Foreign Materials Left in Unit 1 Containment;
- Unit 1 Train B AFW Pump Fire Past Operability;
- RHR Air Operated Valve Positioner Arm Failure; and
- Unventable Gas Voids in Containment Recirculation Sump Piping.

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

This inspection constitutes five samples as defined in IP 71111.15-05.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

.1 Post Maintenance Testing

a. Inspection Scope

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

- Unit 1 Train B AFW Pump Fire Related Repair;
- Auxiliary Building Ventilation 0E Charcoal Booster Fan Damper Work Window;
- Unit 0 Component Cooling Pump Work Window; and
- Unit 1 Train B Centrifugal Charging Pump Emergent Shaft Collar Repair.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion), and test documentation was properly evaluated. The inspectors evaluated the activities against

TS, the UFSAR, 10 CFR 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the corrective action program and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment.

This inspection constitutes four samples as defined in IP 71111.19-05.

b. Findings

No findings of significance were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the outage schedule and contingency plans for the Unit 1 refueling outage, conducted March 24, 2008, through April 14, 2008, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the refueling outage, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below.

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the outage schedule for key safety functions and compliance with the applicable TS when taking equipment out of service.
- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing.
- Controls over the status and configuration of electrical systems to ensure that TS and outage schedule requirements were met, and controls over switchyard activities.
- Monitoring of decay heat removal processes, systems, and components.
- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system.
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.
- Controls over activities that could affect reactivity.
- Refueling activities, including fuel handling.
- Startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the containment to verify that debris had not been left which could block emergency core cooling system (ECCS) suction strainers, and reactor physics testing.
- Licensee identification and resolution of problems related to refueling outage activities.

In addition to documentation reviews, the inspectors observed the initial Unit 1 head removal lift as well as the final head reinstallation. The inspectors verified that the height limitations were maintained during the lifts. Documents reviewed are listed in the Attachment to this report.

This inspection constitutes one refueling outage sample as defined in IP 71111.20-05.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Routine Surveillance Testing

a. Inspection Scope

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

- Unit 2 Diesel Driven AFW Pump Monthly Surveillance;
- Unit 1 Bus 112 125V Battery Charger Operability Test;
- Fire Hazard Panel 18-month Surveillance;
- Unit 2 Reactor Containment Fan Cooler Monthly Surveillance; and
- Unit 1 Reheat and Intercept Valve Quarterly Surveillance.

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

- any preconditioning occurred;
- effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented; as left setpoints were within required ranges;
- the calibration frequency was in accordance with TS, the UFSAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current; test equipment was used within the required range and accuracy;
- applicable prerequisites described in the test procedures were satisfied; test frequencies met TS requirements to demonstrate operability and reliability;
- tests were performed in accordance with the test procedures and other applicable procedures;
- jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;

- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of the safety functions;
- and all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment.

This inspection constitutes five routine surveillance testing sample as defined in IP 71111.22 Sections -02 and -05.

b. Findings

No findings of significance were identified.

.2 Inservice Testing Surveillance

a. Inspection Scope

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

- Unit 1 Train B AFW System Full Flow Test (IST).

The inspectors observed activities and reviewed procedures and associated records to determine whether:

- any preconditioning occurred;
- effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented; as left setpoints were within required ranges;
- and the calibration frequency were in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability;

- tests were performed in accordance with the test procedures and other applicable procedures;
- jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of ASME Code, Section XI, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions;
- and all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment.

This inspection constitutes one inservice inspection sample as defined in Inspection Procedure 71111.22-05.

b. Findings

No findings of significance were identified.

.3 RCS Leak Detection Inspection Surveillance

The inspectors reviewed the test results for the following activity to determine whether the equipment was capable of performing its intended function of monitoring RCS leakage and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- Unit 2 RCS Water Inventory Balance February 7, 2008

The inspectors observed in plant activities and reviewed procedures and associated records to determine whether:

- preconditioning occurred;
- effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;

- as left setpoints were within required ranges, and the calibration frequency were in accordance with TSs, the USAR, procedures, and applicable commitments; measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy;
- applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability;
- tests were performed in accordance with the test procedures and other applicable procedures;
- jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid; test equipment was removed after testing;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- and all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment.

This inspection constitutes one RCS leak detection inspection sample as defined in IP 71111.22-05.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System (ANS) Evaluation (71114.02)

.1 ANS Evaluation

a. Inspection Scope

The inspectors reviewed documents and conducted interviews with Emergency Preparedness (EP) staff regarding the operation, maintenance, and periodic testing of the ANS in the Byron Station's plume pathway Emergency Planning Zone. The inspectors reviewed monthly trend reports and siren test failure records from April 2006 through March 2008. Information gathered during document reviews and interviews was used to determine whether the ANS equipment was maintained and tested in accordance with Emergency Plan commitments and procedures.

This inspection constitutes one sample as defined in IP 71114.02-05.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation Testing (71114.03)

.1 ERO Augmentation Testing

a. Inspection Scope

The inspectors reviewed and discussed with plant EP staff the emergency plan commitments and procedures that addressed the primary and alternate methods of initiating an ERO activation to augment the on-shift ERO as well as the provisions for maintaining the plant's ERO roster. The inspectors also reviewed reports and a sample of corrective action program records of unannounced off hour augmentation tests, which were conducted from February 2006 through January 2008 to determine the adequacy of problem identification and associated corrective actions. The inspectors also reviewed a sample of the EP training records, approximately 26 records for ERO personnel, who were assigned to key and support positions, to determine the status of their training related to their assigned ERO positions.

This inspection constitutes one sample as defined in IP 71114.03-05.

b. Findings

No findings of significance were identified.

1EP5 Correction of EP Weaknesses and Deficiencies (71114.05)

.1 Correction of EP Weaknesses and Deficiencies

a. Inspection Scope

The inspectors reviewed a sample of the Nuclear Oversight staff's 2006 and 2007 audits of the Byron Station EP program to determine whether these independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also reviewed critique reports and samples of corrective action program records associated with the 2007 biennial exercise, as well as various EP drills conducted in 2007, in order to determine whether the licensee fulfilled its drill commitments and to evaluate the licensee's efforts to identify, track, and resolve concerns identified during these activities. Additionally, the inspectors reviewed one actual emergency plan activation that involved an Alert declaration on November 27, 2007, due to toxic or asphyxiate gases in the plant. The inspectors independently evaluated the event and the licensee self-assessment to determine if the licensee effectively implemented the requirements of the emergency plan. The inspectors reviewed a sample of EP items and corrective actions related to the facility's EP program and activities to determine whether corrective actions were completed in accordance with the sites CAP.

This inspection constitutes one sample as defined in IP 71114.05-05.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

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

a. Inspection Scope

The inspectors reviewed the licensee's occupational exposure control cornerstone performance indicators (PIs) to determine whether the conditions resulting in any PI occurrences had been evaluated, and identified problems had been entered into the CAP for resolution.

This inspection does not constitute an inspection sample as defined in IP 71121.01-5, but it does supplements the sample reported in inspection report 05000454/2008002; 05000455/2008002.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit (RWP) Reviews

a. Inspection Scope

The adequacy of the licensee's internal dose assessment process for internal exposures >50 millirem committed effective dose equivalent was assessed. There were no internal exposures >50 millirem committed effective dose equivalent.

This inspection constitutes one required sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed a sample of the licensee's self-assessments, audits, Licensee Event Reports (LERs), and Special Reports related to the access control program to verify that identified problems were entered into the CAP for resolution.

Also, the inspectors reviewed licensee documentation packages for all PI events occurring since the last inspection to determine if any of these PI events involved dose rates >25 R/hr at 30 centimeters or >500 R/hr at 1 meter. Barriers were evaluated for failure and to determine if there were any barriers left to prevent personnel access. There were no events of unintended exposures >100 millirem total effective dose equivalent (or >5 rem shallow dose equivalent or >1.5 rem lens dose equivalent), therefore a substantial potential for an overexposure did not occur.

This inspection constitutes two required samples as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

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

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective exposure history, current exposure trends, ongoing and planned activities in order to assess current performance and exposure challenges. This included determining the plant's current three-year rolling average for collective exposure in order to help establish resource allocations and to provide a perspective of significance for any resulting inspection finding assessment.

Also, the inspectors reviewed documents to determine if there were site-specific trends in collective exposures and source-term measurements.

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

This inspection constitutes three required samples as defined in IP 71121.02-5.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors compared the results achieved including dose rate reductions and person-rem used with the intended dose established in the licensee's ALARA planning for these work activities. Reasons for inconsistencies between intended and actual work activity doses were reviewed.

This inspection constitutes one required sample as defined in IP 71121.02-5.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

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

Additionally, the licensee's exposure tracking system was evaluated to determine whether the level of exposure tracking detail, exposure report timeliness, and exposure report distribution was sufficient to support control of collective exposures. RWPs were reviewed to determine if they covered too many work activities to allow work activity specific exposure trends to be detected and controlled. During the conduct of exposure significant work, the inspectors evaluated if licensee management was aware of the exposure status of the work and would intervene if exposure trends increased beyond exposure estimates.

This inspection constitutes one required and one optional sample as defined in IP 71121.02-5.

b. Findings

No findings of significance were identified.

.4 Source-Term Reduction and Control

a. Inspection Scope

The inspectors reviewed licensee records to determine the historical trends and current status of tracked plant source terms and determined that the licensee was making allowances and had developing contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry.

Also, the inspectors verified that the licensee had developed an understanding of the plant source-term, that this included knowledge of input mechanisms to reduce the source term and that the licensee had a source-term control strategy in place that included a cobalt reduction strategy and shutdown ramping and operating chemistry plan which was designed to minimize the source-term external to the core. Other methods used by the licensee to control the source term including component and system decontamination, and use of shielding were evaluated.

This inspection constitutes one required and one optional sample as defined in IP 71121.02-5.

b. Findings

No findings of significance were identified.

.5 Declared Pregnant Workers

a. Inspection Scope

The inspectors reviewed dose records of declared pregnant workers for the current assessment period to verify that the exposure results and monitoring controls employed by the licensee complied with the requirements of 10 CFR Part 20.

This inspection constitutes one required sample as defined in IP71121.02-5.

b. Findings

No findings of significance were identified.

.6 Problem Identification and Resolutions

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, and Special Reports related to the ALARA program since the last inspection to determine if the licensee's overall audit program's scope and frequency for all applicable areas under the Occupational Cornerstone met the requirements of 10 CFR 20.1101(c).

Additionally, the licensee's CAP program was also reviewed to determine if repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution had been addressed.

This inspection constitutes two required samples as defined in IP 71121.02-5.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 PI Verification (71151)

.1 Drill/Exercise Performance

a. Inspection Scope

The inspectors sampled licensee submittals for the Drill/Exercise Performance PI for the period from the second quarter 2007 through fourth quarter 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicators in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI; assessments of PI opportunities during pre-designated control room simulator training sessions, performance during the 2007 biennial exercise, and performance during other drills. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one drill/exercise performance sample as defined by IP 71151-05.

b. Findings

No findings of significance were identified.

.2 ERO Drill Participation

a. Inspection Scope

The inspectors sampled licensee submittals for the ERO Drill Participation PI for the period from the second quarter 2007 through fourth quarter 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, Revision 5, were used. The inspectors reviewed the licensee's records associated with the performance indicator to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI; performance during the 2007 biennial exercise and other drills; and revisions of the roster of personnel assigned to key emergency response organization positions. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one ERO drill participation sample as defined by IP 71151-05.

b. Findings

No findings of significance were identified.

.3 ANS

a. Inspection Scope

The inspectors sampled licensee submittals for the ANS PI for the period from the second quarter 2007 through fourth quarter 2007. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, Revision 5, were used. The inspectors reviewed the licensee's records associated with the PI to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI and results of periodic ANS operability tests. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one alert and notification system sample as defined by IP 71151-05.

b. Findings

No findings of significance were identified.

.4 Unplanned Power Changes per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Power Changes per 7000 Critical Hours PI for Units 1 and 2 for the second quarter 2007 through fourth quarter 2007. To determine the accuracy of the PI data reported during those periods, the inspectors used PI definitions and guidance contained in Revision 5 of NEI 99-02. The inspectors reviewed the licensee's operator narrative logs, issue reports, maintenance rule records, event reports, and NRC integrated inspection reports for this period to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes two samples of the Unplanned Power Changes per 7000 Critical Hours PI as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.5 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the Occupational Radiological Occurrences PI for the period of July 2007 through March 2008. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI 99-02, Revision 5, were used. The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety to determine if indicator related data was adequately assessed and reported. To assess the adequacy of the licensee's PI data collection and analyses, the inspectors discussed with radiation protection staff, the scope and breadth of its data review, and the results of those reviews. The inspectors independently reviewed electronic dosimetry dose rate and accumulated dose alarm and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted walkdowns of numerous locked high and very high radiation area entrances to determine the adequacy of the controls in place for these areas. Specific documents reviewed are described in the Attachment to this report.

This inspection constitutes one required occupational radiological occurrences sample as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of items Entered Into the CAP

a. Inspection Scope

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

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter and documented in Sections 1 and 2 of this report.

b. Findings

No findings of significance were identified.

a. (Open) Unresolved Item (URI) 05000454/455/2008003-06: Unit 1 and Unit 2 AFW Tunnel Hatch Margin to Safety

Late in the inspection period the licensee identified that the design analysis for evaluation of the AFW tunnel flood seal covers did not include the effects of a high energy line break in the main steam isolation valve tunnels at another facility. The NRC inspectors at that facility questioned why a dynamic load factor as a result of the impulse pressure following a high energy line break had not been considered in an analytic calculation perform to support the operability evaluation.

Following a review of the licensee's evaluation, the inspectors questioned the licensee's conclusion that the operability of the AFW hatches continued to be supported despite analytical results showing a factor of safety for the concrete expansion anchors supporting the hatches of less than 2.0, which is contrary to the guidance provided in NRC Bulletin 79-02, "Pipe Support Base Plate Designs Using Concrete Expansion Anchors." Additionally, the inspectors noted that the licensee's evaluation did not address Section C.13 of NRC Technical Guidance 9900, "Operability Determinations & Functionality Assessment for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety." Specifically, Section C.13 stated that if a structure was degraded, the licensee should assess the structure's capability of performing its specified function. As long as the identified degradation did not result in exceeding acceptance limits specified in applicable design codes and standards referenced in the design basis documents, the affected structure was either operable or functional. The licensee also identified additional errors that reduced the margin of safety for the structural integrity of a high energy line break barrier.

At the close of the inspection period temporary modifications had been implemented at both facilities that restored the margin of safety to greater than 2.0. Pending additional follow-up by the inspectors for the past operability and timeliness of corrective actions, extent of condition, and corrective actions, this item will remain open.
(URI 005000454/2008003-06; 05000455/2008003-06)

.2 Daily CAP Reviews

a. Scope

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

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

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the six month period of December 1, 2007 through May 31, 2008, although some examples expanded beyond those dates where the scope of the trend warranted.

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

This review constituted a single semi-annual trend inspection sample.

b. Findings

The inspectors identified two apparent trends during this review. The first trend is the identification by the NRC of six findings or violations with a cross cutting aspect of decision making within the last four calendar quarters. Three of these findings were documented in NRC inspection report 05000454/2007009, two of the findings were documented in NRC inspection report 05000454/2007004 and the remaining item was documented in this inspection report. Four of these items were in the Mitigating Systems cornerstone and two were in the Initiating Events cornerstone.

The licensee had previously implemented a Human Performance Improvement Plan (HPIP) as part of a previous negative trend. This trend was initially documented in the NRC Mid-Cycle Review dated August 30, 2005 as a substantive cross cutting issue. The licensee's corrective actions were assessed and based upon that assessment and a declining trend of cross cutting issues the substantive cross cutting issue was closed in the Mid-Cycle Review dated August 31, 2006.

The inspectors' assessment determined that the licensee had recognized the new trend and taken actions to address the declining performance. However, these actions had not yet proven effective in substantially mitigating the adverse trend.

The second trend identified during this semi-annual trend review was a negative trend in plant aging issues. Examples included:

- Station Auxiliary Transformer 242-2 failure documented in this inspection report was identified by the licensee as caused by age related failure of an electrical insulator;

- The fire on the Unit 1 Train B diesel driven auxiliary feedwater pump was identified by the licensee as age related relaxation of the exhaust manifold bolts along with an inadequate preventative maintenance program. This item was documented in this inspection report;

- The licensee's unplanned entry into an Orange risk condition, documented in this inspection report, was to correct long standing age-related issues with poor material condition of certain SX valves. These valves had not been removed for maintenance since initial startup;

- The degradation of the SX return header piping risers to the Ultimate Heat Sink cooling tower was an age related degradation combined with inadequate corrective actions. This item was documented in NRC inspection report 05000454/2007009;

- In the Spring of 2006 the licensee identified degraded vacuum breakers on the blowdown line to the river. The vacuum breakers had degraded over time and were not receiving maintenance. The issue related to leaking vacuum breakers was documented in NRC inspection report 05000454/2006-002 and 05000454/2006004; and

- The degradation of non-safety related circulating water piping was identified in the basement of the Unit 1 and Unit 2 turbine building. This degradation was found as part of the extent of condition assessment by the licensee to the SX riser issue. This piping was degraded due to the licensee's practice of draining water to the area around the piping during refueling outages which over many years caused pipe corrosion.

Each of the first five examples listed above received appropriate regulatory follow-up in the inspection reports listed. The last example was not of direct regulatory significance and was not documented in an NRC inspection report. In response to the above issues, most notably the SX riser degradation the licensee has greatly increased their assessment of the current condition of plant equipment and has significantly increased the efforts spent to address these issues. Nevertheless as the plant continues to operate age related degradation will cause challenges.

No findings of significance were identified.

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

.1 Plant Response to Seismic Activity

a. Inspection Scope

The inspectors reviewed the plant's response to a seismic event. On April 18, 2008, an earthquake occurred in Southern Illinois. No individual at the licensee's facility felt the earthquake and no instrumentation on site detected the earthquake but personnel offsite did feel the earthquake and reported it to the control room personnel. Shift personnel entered the appropriate abnormal operating procedure and attempted to contact the National Earthquake Information Center but were only able to leave a message. Subsequently licensee personnel performed an inspection of selected plant facilities and systems and did not identify any damage. The inspectors also performed a walkdown of licensee facilities and systems and did not identify any damage. The licensee issued a corporate wide Press Release and made a voluntary Event Notification to the NRC Headquarters Operations Officer. Documents reviewed in this inspection are listed in the Attachment.

This inspection constitutes one sample as defined in IP 71153.

b. Findings

No findings of significance were identified.

.2 (Closed) LER 05000454/2008-001-00: "Technical Specification Non-Compliance of Containment Sump Monitor Due to Improper Installation During Original Construction."

This LER, addresses a past operability issue with the Unit 1 containment floor drain sump flow monitor that was discovered on March 28, 2008. Technical Specification3.4.15, "RCS Leakage Detection Instrumentation," required one containment sump monitor to be operable in order to detect reactor coolant system leaks. The sump was required to be able to detect a one gpm leak within one hour.

During a refueling outage a member of the licensee's staff questioned the operability of the sump with penetrations through the cover allowing water to flow into the sump while bypassing the leakage measuring device. Subsequently the licensee determined the sump was improperly installed and had been so since initial construction in 1976.

A corrective action document was written and the sump was modified to restore operability prior to the restart of the unit. This same error had previously existed on Unit 2 but had been inadvertently corrected in 2004 during a modification to install a different type of sump level instrument. Alternative equipment existed to assist the operators in identifying RCS unidentified leakage. These instruments included a containment radiation monitor, volume control tank level indicators, post accident containment sump level instruments, containment pressure indicators, containment temperature indicators, and pressurizer level instruments. The enforcement aspects of this finding are discussed in Section 4OA7 of this report. Documents reviewed as part of this inspection are listed in the Attachment. This LER is closed.

This inspection constitutes one sample as defined in IP 71153.

.3 (Closed) LER 05000455/2008-001-00: "Unit 2 Emergency Diesel Generators and Auxiliary Feedwater Pump Automatic Start Resulting from a Loss of Offsite Power Due to a Failed Insulator Causing a Differential Phase Overcurrent."

This event was previously discussed in Inspection Report 05000454/2008002; 05000455/2008002, Section 4OA3, and in Section 1R12 of this Report. The NRC reviewed the event risk in accordance with Management Directive 8.3, "NRC Incident Investigation Program," and determined that the conditional core damage probability did not warrant additional inspection. Documents reviewed as part of this inspection are listed in the Attachment. This LER is closed.

This inspection constitutes one sample as defined in IP 71153.

4OA5 **Other Activities**

.1 Follow-up of Backfit Activities

a. Inspection Scope

As documented in Inspection Report 05000454/2008008; 05000455/2008008, the inspectors identified the licensee did not consider spurious failure/opening of the 4160 volt or 480 Volts AC as a valid single failure in Amendment No. 95. The inspectors further noted that the NRC did not evaluate the potential for a passive failure of the electrical breakers even though passive failures were required to be evaluated under 10 CFR Part 50, Appendix A. After further review, the inspectors determined that the provisions of 10 CFR 50.109(a)(4), were applicable and that a modification is necessary to bring a facility into compliance with the rules or orders of the NRC. The licensee was requested to respond with a description of the intended actions to address the noncompliance including a proposed schedule to complete those actions.

In a letter dated June 4, 2008, from D. Hoots (ADAMS Accession No. ML081560649), the licensee stated that a design basis re-analysis of the ultimate heat sink would be completed by December 5, 2008. This issue is considered open pending completion of the licensee's re-analysis. (OTHR 05000454/2008003-07; 05000455/2008003-07)

.2 RCS Dissimilar Metal Butt Welds (DMBW) (TI 2515/172, Revision 0)

a. Inspection Scope

The inspectors conducted a review of the licensee's activities regarding DMBW mitigation and inspection implemented in accordance with the industry self-imposed mandatory requirements of Materials Reliability Program, (MRP) -139, "Primary System Piping Butt Weld Inspection and Evaluation Guidelines." TI 2515/172, "Reactor Coolant System Dissimilar Metal Butt Welds," was issued February 21, 2008, to support the evaluation of the licensees' implementation of MRP-139. This review was conducted for both Units 1 and 2 unless otherwise noted.

The documents reviewed by the inspector for this inspection are listed in the Attachment to this report.

From March 24, 2008 through April 3, 2008, the inspectors performed a review in accordance with TI-172 which included the following:

(1) Licensee's Implementation of the MRP-139 Baseline Inspections

The inspectors verified that the licensee's inspection program included inspections of the pressurizer, hot let and cold leg temperature DMBWs and that the schedules for these baseline inspections are consistent with the requirements stated in MRP-139. If any baseline inspection schedules deviated from MRP-139 guidelines, the inspectors also determined what deviations were planned and what the general basis for the deviation was.

The inspectors verified that the licensee had completed MRP-139 baseline inspections of all pressurizer DMBWs by December 31, 2007.

(2) Volumetric Examinations

The inspectors reviewed the volumetric examinations of the Unit 1 reactor vessel outlet safe end to nozzle weld baseline inspection completed in 2005 and the Unit 2 reactor vessel inlet safe end to nozzle weld baseline inspection completed in 2007 and verified the examinations were performed in accordance with the guidelines in MRP-139, Section 5.1. The inspectors also verified that these examinations were performed by qualified personnel and that any deficiencies identified were appropriately dispositioned and resolved.

The inspectors reviewed the volumetric examinations of the Unit 1 pressurizer surge nozzle overlay completed in 2006 and the Unit 2 pressurizer relief valve nozzle overlay completed in 2007 and verified the examination was performed consistent with the NRC staff relief request authorization for the weld overlay. If the inspection coverage warranted further evaluation, the inspector also reviewed the licensee's documentation of the basis for achieving the required inspection coverage.

The inspectors verified that the above examinations were performed by qualified personnel and that any deficiencies identified were appropriately dispositioned and resolved.

(3) Weld Overlays

During the current outage no weld overlays pertinent to MRP-139 were performed on Unit 1. The inspectors reviewed weld overlay documentation for the Unit 1 pressurizer surge nozzle overlay and the Unit 2 pressurizer relief valve nozzle overlay to verify that the welds were performed in accordance with NRC staff relief request authorizations and the ASME Code. The inspectors also verified that the welds were performed by qualified personnel and that any deficiencies were appropriately dispositioned and resolved.

(4) Mechanical Stress Improvement

There were no mechanical stress improvement activities performed or planned by the licensee to comply with their MRP-139 commitments. Hence, NRC inspection of such mechanical stress improvements was not applicable.

(5) ISI Program

The inspectors verified that the licensee's MRP-139 ISI program includes the applicable welds and that the welds are included in categories consistent with MRP-139 guidelines. The inspectors verified that the licensee's inspection program and procedures specified inspection frequencies consistent with Tables 6-1 and 6-2 of MRP-139. The inspectors also determined if any welds were categorized as H or I, and for those welds reviewed the licensee's basis for the categorization and the licensee's plans for addressing potential primary water stress corrosion cracking. The inspector also determined if any deviations were planned from the inspection guidelines of MRP-139.

b. Observations

Summary: Byron Units 1 and 2 are Westinghouse four loop design plants and were determined by the licensee to contain susceptible DMBWs per MRP-139. To date, the pressurizer DMBWs on both units have been mitigated by full structural overlays and have received baseline volumetric examination. The remaining susceptible welds (MRP-139 category "D" and "E") for Units 1 and 2 are planned for possible mitigation in 2011 and 2013 respectively. In accordance with requirements of TI 2515/172, Revision 0, the inspectors evaluated and answered the following questions:

(1) Licensee's Implementation of the MRP-139 Baseline Inspections:

1. a. Have the baseline inspections been performed or are they scheduled to be performed in accordance with MRP-139 guidance?

Yes. Baseline inspections for pressurizer DMBWs were performed post mitigation in the Fall of 2006 for Unit 1 and in the Spring of 2007 for Unit 2. The Category "D" and "E" welds were inspected in the Spring of 2005 for Unit 1 and in the Fall of 2005 for Unit 2.

b. Were the baseline inspections of the pressurizer temperature DMBW's of the nine plants listed in 03.01.b completed during the spring outages?

No. Byron is not one of the nine plants listed in 03.01.b.

2. Is the licensee planning to take any deviations from the MRP-139 baseline inspection requirements? If so, what deviations are planned, what is the general basis for the deviation, and was the NEI- 03-08 process for filing a deviation followed?

No. No deviations from the MRP-139 baseline inspection requirements are planned for either unit.

(2) Volumetric Examinations

1. Performed in accordance with the examination guidelines in MRP-139, Section 5.1, for unmitigated welds or mechanical stress improvement welds and consistent with NRC staff relief request authorization for weld overlaid welds?

   Yes. The inspectors reviewed the volumetric examinations of the Unit 1 pressurizer surge nozzle overlay completed in 2006 and the Unit 2 PORV nozzle overlay completed in 2007 and verified the examination was performed consistent with the NRC staff relief request authorization for the weld overlay. The inspectors also reviewed the volumetric examinations of the Unit 1 reactor vessel outlet safe end to nozzle weld baseline inspection completed in 2005 and the Unit 2 reactor vessel inlet safe end to nozzle weld baseline inspection completed in 2007 and verified the examinations were performed in accordance with the guidelines in MRP-139, Section 5.1.

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

   Yes. The UT examiners were qualified to the applicable ASME Code, Section XI, Appendix VIII, PDI requirements.

   Performed such that deficiencies were identified, dispositioned, and resolved?

   Yes. Indications were identified in the weld overlay for several DMBWs on both the Unit 1 and Unit 2 pressurizers. The inspectors reviewed the evaluations performed for the Unit 1 surge nozzle overlay and the Unit 2 PORV nozzle overlay and determined that the evaluations were acceptable.

(3) Weld Overlays

1. Performed in accordance with ASME Code welding requirements and consistent with NRC staff relief request authorizations? Has the licensee submitted a relief request and obtained NRR staff authorization to install the weld overlays?

   Yes. Weld overlay documentation for the Unit 1 surge nozzle overlay and the Unit 2 PORV nozzle overlay were reviewed. The welds were performed in accordance with NRC staff relief request authorizations and the ASME Code.

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

   Yes. Welders were qualified in accordance with ASME Code, Section IX and were verified to be current.

3. Performed such that deficiencies were identified, dispositioned, and resolved?

Yes. Welds were performed in accordance with the ASME Code and 10 CFR 50, Appendix B requirements.

(4) Mechanical Stress Improvement

There were no stress improvement activities performed or planned by this licensee to comply with their MRP-139 commitments.

(5) ISI Program

1. Has the licensee prepared an MRP-139 ISI program? If not, briefly summarize the licensee's basis for not having a documented program and when the licensee plans to complete preparation of the program.

   Yes. Susceptible welds were appropriately included in the program and categorization and inspection schedules are in accordance with MRP-139 guidance.

2. In the MRP-139 ISI program, are the welds appropriately categorized in accordance with MRP-139? If any welds are not appropriately categorized, briefly explain the discrepancies.

   Yes. Welds included in the MRP-139 program were properly categorized.

3. In the MRP-139 ISI program, are the ISI frequencies, which may differ between the first and second intervals after the MRP-139 baseline inspection, consistent with the inservice inspections frequencies called for by MRP-139?

   Yes. Those DMBWs which have been overlaid and those yet to be mitigated are scheduled for reexamination in accordance with MRP-139.

4. If any welds are categorized as H or I, briefly explain the licensee's basis of the categorization and the licensee's plans for addressing potential primary water stress corrosion cracking (PWSCC).

   Pressurizer DMBWs (safety valve, relief valve, spray, and surge line nozzles) for both units were categorized as "H" due to a lack of qualified technique which prevented an Appendix VIII examination. These welds, on both units have been mitigated by full structural weld overlays.

5. If the licensee is planning to take deviations from the inservice inspection "requirements" of MRP-139, what are the deviations and what are the general bases for the deviations? Was the NEI 03-08 process for filing deviations followed?

   No. No deviations are currently planned for either unit.

c. Findings

No findings of significance were identified.

.3 <u>(Closed) Unresolved Item (URI) 05000455/2008002-03: Unit 2 Notice of Unusual Event due to Loss of Both SATs</u>

On March 25, 2008, Unit 2 SAT 242-2 de-energized upon receipt of a C phase to ground relay actuation. As designed the upstream switchyard breakers opened de-energizing both SAT 242-1 and 242-2. Also, as designed, the downstream breakers opened resulting in a fast transfer of the 6.9KiloVolt buses to the Unit Auxiliary Transformers and the transfer of the 4KiloVolt buses to the EDGs which had automatically started. The licensee entered a Notification of Unusual Event and the NRC entered the Monitoring Mode. The licensee subsequently transferred the 4KiloVolt loads to the Unit 1 SATs and began troubleshooting efforts. Following verification that a fault did not exist on the SAT 242-1 circuit all Unit 2 house loads were transferred to SAT 242-1. Subsequently the licensee exited the Unusual Event and the NRC exited the Monitoring Mode.

The inspectors reviewed the plant's and the operators' responses to the loss of both unit SATs to determine if the responses were appropriate and in accordance with design, procedures and training.

At the close of the previous inspection period additional information was required to determine if the loss of the SAT was a finding, or if it constituted a deviation or violation. The additional information needed was the results of the licensee's root cause evaluation and proposed corrective actions. The inspectors reviewed the licensee's root cause analysis report, additional documentation, and interviewed licensee personnel. The root cause analysis determined that the SAT tripped due to the failure of a ceramic insulator on the B-Phase of the 4KiloVolt non-segregated bus duct. Routine preventive testing of the bus duct did not identify the degraded insulator. The testing performed was in accordance with licensee procedures and industry recommended practices. Based upon these reviews, the inspectors determined that the loss of the SAT was not a finding, deviation, or violation. Documents reviewed are listed in the Attachment. This URI is closed.

.4 <u>(Closed) URI 05000455/2008002-04: Unit 1 Train B Auxiliary Feedwater Pump Diesel Fire and Shutdown During Surveillance</u>

On March 21, 2008, during a routine 18-month surveillance test of the Unit 1 AFW pump, the operator in the room reported that the diesel was on fire. The diesel driven AFW pump was shutdown and declared inoperable resulting in the licensee entering a 72 hour shutdown Limiting Condition for Operation. Subsequently, the licensee shutdown for a planned refueling outage, exiting the applicable operating modes, and negating the need to repair the diesel within 72 hours. Prior to the end of the refueling outage the licensee repaired the diesel, performed appropriate surveillance tests, and declared the diesel driven pump operable. Review was performed as part of IP 71111.15, Operability Evaluations and after reviewing engineering documents, interviewing operators, and performing a specific assessment of the effects of a carbon dioxide release on the operation of the diesel the inspectors agreed with the licensee's conclusion that the diesel remained operable during the fire. Even if the operators secure the AFW pump in the event of a fire, they would be able to restart the pump as necessary as the pump is fully operable. Documents reviewed are listed in that section. This URI is closed.

.5 (Closed) NRC Temporary Instruction (TI) 2515/166, "Pressurized Water Reactor Containment Sump Blockage (NRC Generic Letter 2004-02)" – Units 1 and 2

a. Inspection Scope

The inspectors reviewed the station implementation of the licensee's commitments documented in their December 31, 2007, response to Generic Letter (GL) 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized Water Reactors." The inspectors performed walkdowns and reviewed the Engineering Change Packages (ECs) associated with the ECCS throttle valves modifications and the 10 CFR 50.59 evaluations for these ECs. In addition, the inspectors reviewed: two samples of the completed and approved for use changes for the UFSAR, Revision 12, that have not been incorporated yet; one sample of an in-route change for the UFSAR, Revision 12; and one sample already incorporated in Revision 11. The documents reviewed are listed at the end of the report. The inspection was conducted in accordance with TI 2515/166.

b. Inspection Documentation

The inspectors determined the following answers to the Reporting Requirements detailed in the TI 2515/166:

(1) Did the licensee implement the plant modifications and procedure changes committed to in their GL 2004-02 responses?

The licensee has implemented the plant modifications and procedure changes committed to in their GL 2004-02. In addition, the licensee cancelled the cyclone separator modification for Unit 1 because test results showed that they are not susceptible to blockage as documented in EC 364979, "Evaluate SI Throttle Valve Test Results from Wyle Labs to Document Acceptability of New Trim Design." The commitments included:

- Installation of permanent modification of the sump strainer assemblies.

  This commitment was previously reviewed and documented in NRC Inspection Reports 05000454/2007003 and 05000455/2007003. Structural analyses of the new strainer assemblies were performed through BYR06-025, "Design Loads and Sizing Limitations for the ECCS Containment Sump Trash Rack," and 3 SA-096-016, "CCI Structural Analysis of Strainer and Support Structure."

- Installation of permanent modification of the ECCS throttle valves at Unit 2 and replacement of the fibrous insulation with reflective metal insulation within the zone of influence at Unit 1.

  This commitment was previously reviewed and documented in NRC Inspection Reports 05000454/2008006 and 05000455/2008006.

- Installation of permanent modification of the ECCS throttle valves at Unit 1 for which licensee received approval for an extension until Spring 2008.

This modification was completed at the time of this inspection and was documented in EC 359455, "Downstream Activities Effects Related to [Generic Safety Issue] (GSI) -191 – U1." In addition, the inspectors performed a walkdown of this modification.

- Perform latent debris walkdowns, and debris generation and transport analyses.

  The commitment to perform containment walkdowns was previously reviewed and documented in NRC Inspection Report 05000454/2008006 and 05000455/2008006. The debris generation was estimated by S040-BY-5010, "GSI-191 Latent Debris Collection-Unit 1," and S040-BY-5030, "GSI-191 Latent Debris Collection-Unit 2." Debris generation was analyzed by BYR05-041, "GSI-191 post-LOCA Debris Generation." Debris transportation was analyzed through BYR05-042, "Post-LOCA Debris Transport Evaluation for Resolution of GSI-191."

- Perform evaluation of strainer performance including chemical effects.

  Head loss testing and analysis, including chemical effects, were previously reviewed and documented in NRC Inspection Report 05000454/2008006 and 05000455/2008006. In addition, the following tests were reviewed: (1) DIT-BYR-06-007, "Debris Concentration Measurements Results," and (2) BYR-05-061, "GSI-191 Evaluation of Long Term Downstream Effects."

- Perform evaluation of downstream and upstream effects.

  Downstream effects analysis for fuel, vessel, and component wear and blockage were previously reviewed and documented in NRC Inspection Report 05000454/2008006 and 05000455/2008006. Testing of wear and blockage to the ECCS throttle valves and Containment Spray System Cyclone Separator was documented in EC 364979, "Evaluate SI Throttle Valve Test Results from Wyle Labs to Document Acceptability of New Trim Design." Upstream effects were evaluated by S040-BYR-5032, "GSI-191 Debris Generation Walkdown-U2," and S040-BYR-5011, "GSI-191 Debris Generation Walkdown-U1."

- Determine minimum available net positive suction head margin for the RHR pumps at switchover to sump recirculation.

  Minimum available net positive suction head margin was previously reviewed and documented in NRC Inspection Report 05000454/2008006 and 05000455/2008006. The hydraulic model of the ECCS was performed by BYR06-029, "SI/RHR/CS/CV System Hydraulic Analysis in Support of GSI-191."

- Establish programmatic controls to ensure that potential sources of debris introduced into containment are assessed for adverse affects.

  The licensee performed an enhancement to CC-AA-102, "Design Input and Configuration Change Impact Screening," to introduce a requirement to review the impact of a proposed change on the documentation that forms the design basis for their response to GL 2004-02. In addition, the licensee upgraded OP-AA-116-101, “Equipment Labeling,” and committed to use 1/2 BOSR Z.5.1.1-1, “Containment Loose Debris Inspection,” CC-AA-205, “Control of Undocumented/Unqualified Coatings Inside Containment,” and 1/2 BVSR XII-11, “Containment Building Interior Surface Coating Inspection” as administrative controls for limiting debris sources inside containment. Also, latent debris measurements inside containment every four refueling outages are currently being tracked by Predefines 174052 and 174053. IR 777152 is tracking the addition of a note explaining the basis for the activity and a caution to factor in the impact of changes to it when the procedure is generated.

(2) Has the licensee updated its licensing bases to reflect the corrective actions taken in response to GL 2004-02?

The licensee has updated its licensing bases to reflect the corrective actions taken in response to GL 2004-02 with the exception of one change to the UFSAR relevant to the recently completed modification of the ECCS throttle valves for Unit 1. This UFSAR change is pending licensee approval.

(3) If the licensee or plant has obtained an extension past the completion date of this TI, document what actions have been completed and what actions are outstanding.

The licensee requested and received approval for an extension until spring 2008 to complete the installation of ECCS throttle valves for Unit 1. During the refueling outage of spring 2008, the licensee completed this action.

Completed actions are:

- Installation of new strainer assemblies for both units;
- Installation of modified ECCS throttle valves at both units;
- Replacement of fibrous insulation with reflective metal insulation within the zone of influence at Unit 1;
- Programmatic controls had been put in place;
- Associated analyses and testing; and
- Licensing bases update of the pertinent completed actions.

Outstanding actions are:

- Licensing bases update relevant to the ECCS throttle valve modification at Unit 1

This TI is closed for both units. This documentation of TI-2515/166 completion as well as any results of sampling audits of licensee actions will be reviewed by the NRC staff (Office of Nuclear Reactor Regulation - NRR) as input along with the GL 2004-02 responses to support closure of GL 2004-02 and GSI-191, “Assessment of Debris Accumulation on Pressurized-Water Reactor (PWR) Sump Performance." The NRC will notify each licensee by letter of the results of the overall assessment as to whether GSI-191 and GL 2004-02 have been satisfactorily addressed at that licensee’s plant(s). Completion of TI-2515/166 does not necessarily indicate that a licensee has finished all testing and analyses needed to demonstrate the adequacy of their modifications and procedure changes. Licensees may also have obtained approval of plant-specific extensions that allow for later implementation of plant modifications. Licensees will confirm completion of all corrective actions to the NRC. The NRC will track all such yet-to-be-performed items identified in the TI-2515/166 inspection reports to completion and may choose to inspect implementation of some or all of them.

.6 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

Exit Meeting Summary

On July 10, 2008, the inspectors presented the inspection results to Mr. Dave Hoots, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

Interim Exit Meetings

Interim exits were conducted for:

- The Emergency Preparedness Inspection with Mr. D. Hoots on April 11, 2008.
- The Inservice Inspection Procedure 71111.08 and TI 2515/172 with Mr. D. Hoots on April 3, 2008. The inspectors returned proprietary information reviewed during the inspection prior to leaving the site and the licensee confirmed that none of the potential report input discussed was considered proprietary.
- The TI 2515/166, “PWR Containment Sump Blockage (NRC Generic Letter 2004-02)” Inspection with T. Hulbert on May 30, 2008. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.
- The Occupational Radiation Safety Program for Access to Radiologically Significant Areas and ALARA Planning and Controls Inspections with Mr. D. Hoots and other members of the licensee’s staff on June 20, 2008.

4OA7 Licensee-Identified Violations

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

Cornerstone: Mitigating System

- Technical Specification 3.4.15, Condition A, requires that an inoperable containment sump monitor be returned to operable status within 30 days. Technical Specification 3.4.15, Condition C, requires that if Condition A was not met, the unit must be in Mode 3 in 6 hours and in Mode 5 in 36 hours. Contrary to these, Unit 1 was operated since 1976 with the containment sump monitor inoperable. Alternative equipment existed to assist the operators in identifying RCS unidentified leakage. These instruments included a containment radiation monitor, volume control tank level indicators, post accident containment sump level instruments, containment pressure indicators, containment temperature indicators, and pressurizer level instruments. Based upon this, the violation was of very low safety significance. The licensee entered this issue into the corrective action program as IR 755837.

- Technical Specification 5.7.2(c) requires each person entering a locked high radiation area to have an alarming radiation monitoring device that continuously integrates the radiation dose rate (electronic dosimeter). Contrary to the above, on March 29, 2008, an individual entered containment, a posted high radiation area, without an electronic dosimeter. The inspector verified that dose rates >1000 mR/hour were present and that there were no additional physical controls to prevent unauthorized access to these areas. This was identified in the licensee's corrective action program as IR 756342 and corrective actions included removing the individual from the area, reading the individual's thermoluminescent dosimeter, and established single point accountability for individuals controlling access to the locked high radiation area. The finding was determined to be of very low safety significance because it was not an ALARA planning issue, there was no overexposure nor potential for overexposure, and the licensee's ability to assess dose was not compromised. The inspectors discussed with the licensee that this event should have been reported as a PI occurrence for the first quarter of 2008.

- 10 CFR 50.65(a)(4) requires in part, that the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities before performing maintenance. Contrary to the above, between April 5, 2008 to April 6, 2008, the licensee failed to consider that both Unit 1 Essential Service Water Train Cross-tie Isolation Valves, 1SX033 and 1SX034, were left opened and unable to be closed in the main control room in their risk evaluation before conducting the 1A EDG testing. This finding affected the mitigating capability during an internal flooding event in the auxiliary building. The finding was determined to be of very low safety significance for Unit 1 because the unit had been shutdown since March 23, 2008, decay heat load was low, and the time to boil was long. The licensee entered this issue into their corrective action program as IR 759945.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

D. Hoots, Site Vice President
B. Adams, Plant Manager
A. Daniels, NOS Manager
A. Giancatarino, Performance Improvement Director
C. Gayheart, WC Manager
S. Greenlee, Engineering Director
B. Kouba, Operations Support Manager
D. Thompson, Radiation Protection Manager
W. Grundmann, Regulatory Assurance Manager
B. Spahr, Maintenance Director
R. Zuffa, IEMA

Nuclear Regulatory Commission

R. Skokowski, Chief, Branch 3, Division of Reactor Projects

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000454/2008-003-01	NCV	Fire Suppression Sprinkler Obstruction in the Diesel Oil Storage Tank Room
05000454/2008-003-02	NCV	Failure to Correctly Evaluate and Disposition of a Weld Indication
05000454/2008-003-03	NCV	Failure to Perform Evaluation of a Leaking Bolted Connection
05000454, 455/2008-003-04	NCV	Failure to Correctly Tighten Fittings Leads to Failure to Start During a Surveillance of the 0B SX Makeup Pump
05000455/2008-003-05	AV	Failure to Perform an Updated Risk Evaluation Prior to Surveillance Testing of the Unit 1 Train A Diesel Generator Based on Existing Plant Conditions.
05000454, 455/2008-003-06	URI	Unit 1 and Unit 2 Auxiliary Feedwater Tunnel Hatch Margin to Safety
05000454, 455/2008-003-07	OTHR	Design Basis Re-Analysis of the Ultimate Heat Sink

Closed

05000454/2008-003-01	NCV	Fire Suppression Sprinkler Obstruction in the Diesel Oil Storage Tank Room
05000454/2008-003-02	NCV	Failure to Correctly Evaluate and Disposition of a Weld Indication
05000454/2008-003-03	NCV	Failure to Perform Evaluation of a Leaking Bolted Connection
05000454, 455/2008-003-04	NCV	Failure to Correctly Tighten Fittings Leads to Failure to Start During a Surveillance of the 0B SX Makeup Pump
05000454/2008-001-00	LER	Technical Specification Non-Compliance of Containment Sump Monitor Due to Improper Installation During Original Construction
05000455/2008-001-00	LER	Unit 2 Emergency Diesel Generators and Auxiliary Feedwater Pump Automatic Start Resulting from a Loss of Offsite Power Due to a Failed Insulator Causing a Differential Phase Overcurrent
05000455/2008002-03	URI	Unit 2 Notice of Unusual Event due to Loss of Both System Auxiliary Transformers
05000455/2008002-04	URI	Unit 1 Train B Auxiliary Feedwater Pump Diesel Fire and Shutdown During Surveillance

LIST OF DOCUMENTS REVIEWED

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

Section 1R01: Adverse Weather Protection

Byron Condition Reports; Open, Auxiliary Building Ventilation System
Byron Condition Reports; Open, Auxiliary Power System
Byron Condition Reports; Open, Essential Service Water System
Oil Sample Results for UAT 241-2, September 1998 – May 2008
Oil Sample Results for SAT 242-1, September 1990 – March 2008
Oil Sample Results for SAT 242-2, June 1992 – May 2008
Oil Sample Results for 1W MPT, April 1989 – June 2008
IEEE Std C57.104-1991; IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers, November 20, 1991
IR 786022; Switchyard Thermography Needed Following Adverse Weather, June 13, 2008
IR 786025; Emergency Load Reduction Requested and Started, June 13, 2008
OP-AA-108-107-1001; Station Response to Grid Capacity Conditions, Revision 2
OP-AA—108-107-1002; Interface Agreement Between Exelon Energy Delivery and Exelon Generation for Switchyard Operations, Revision 4
OP-AA-108-107; Switchyard Control, Revision 2
WC-AA-8000; Interface Procedure Between Exelon Energy Delivery (Comed/Peco) and Exelon Generation (Nuclear/Power) for Construction and Maintenance Activities, Revision 2
WC-AA-8003; Interface Procedure Between Exelon Generation (Nuclear/Power) for Design Engineering and Transmission Planning Activities, Revision 1

Section 1R04: Equipment Alignment

IR 741835; Start/Stop OB VC from 1PL05JA not performed as scheduled; February 27, 2008
IR 666981; 1A DG Common Mode Failure Evaluation; March 21, 2008
IR 591516; 1A DG Tripped on High JW Temperature During Cooldown; February 14, 2007
IR 759737; 1A DG Failed 1BOSR 8.1.17-1 Due to Low Voltage; April 05, 2008
IR 747616; 1A DG Walkdown Results for NER NC-08-010; March 10, 2008
IR 733706; Auxiliary Electric Room Return Damper Failed Closed; February 08, 2008
IR 585935; OB VC M/U Fan Tripped During a Start for PMT; March 02, 2007
IR 461596; OA VC Train Inoperability – 0VC032Y Failure; March 02, 2006
IR 461319; 0VC032Y Fails, Retested w/o Determining Cause; March 02, 2006
IR 461245; 0VC032Y Will Not Close on M/U Signal; March 02, 2006
BOP VC-M1; Control Room Heating and Ventilation (HVAC) System Valve Lineup; Revision 5
BOP VC-E1; Control Room Ventilation Electrical Lineup; Revision 4
BOP VC-1; Startup of Control Room HVAC; Revision 5
BOP VC-17; Swapping Control Room Chiller and HVAC Trains; Revision 6
BOP DG M1A; Train “A” Diesel Generator System Valve Lineup; Revision 11
BOP DG-E1A; Diesel Generator Train “A”; Revision 2
BOP FC-E1; Fuel Pool Cooling System Electrical Lineup; Revision 2
BOP FC-T3; Spent Fuel Pool Skimmer One-Line Diagram; Revision 0
BOP FC-M1; Fuel Pool Cooling and Cleanup System Valve Lineup; Revision 17

BOP RH-M2B; Train ”B” Residual Heat Removal System Valve Lineup, Revision 7
BOP RH-E2B; Unit 2 Residual Heat Removal System, Train “B” Electrical Lineup, Revision 2
BOP SI-E1B; Unit 1 Safety Injection System Train “B” Electrical Lineup, Revision 3
BOP SI-E1; Unit 1 Safety Injection System Electrical Lineup, Revision 7
BOP SI-M1B; Train “B” Safety Injection System Valve Lineup, Revision 3
BOP SI-E1C; Unit 1 Safety Injection System Electrical Lineup, Revision 4
BOP RH-E2A; Unit 2 Residual Heat Removal System Electrical Lineup, Revision 3
BOP RH-M2A; Train “A” Residual Heat Removal System Valve Lineup, Revision 6
BOP RH-E2; Unit 2 Residual Heat Removal System Electrical Lineup, Revision 0
WR 231867; 1A DG Tripped on High JW Temperature During Cooldown; February 14, 2007
WR 268493; 1A DG Failed 1BOSR 8.1.17-1 Due to Low Voltage; April 06, 2008
WR 265663; DG Walkdown Results for NER NC-08-010; March 11, 2008
WR 262636; Auxiliary Electric Room Return Damper Failed Closed; February 08, 2008
WR 202809; 0VC032Y Will Not Close on M/U Signal; March 03, 2006
Diagram of Safety Injection M-61 Sheet Number 1B, Revision AW
Diagram of Residual Heat Removal M-137, Revision BD

Corrective Action Documents as a Result of NRC Inspection

IR 761127; NRC Identified Tagging Issues – Not B1R15 Related, April 9, 2008
IR 766819; NRC Identified – 1SI8804B Frayed Sealtite, April 23, 2008
IR 766814; NRC Identified – 1SI8806 Old Grease Leaking from Actuator, April 23, 2008
IR 769637; NRC Identified Procedure Discrepancy, April 30, 2008

Section 1R05: Fire Protection

Permanent Scaffold Request B4855, April 3, 2004
Unit 1 Diesel Fuel Oil Storage Room 1A, Zone 10.2-1, January 31, 2007
Unit 1 Diesel Fuel Oil Storage Room 1B, Zone 10.1-1
Unit 2 Diesel Fuel Oil Storage Room 2A, Zone 10.2-2, January 31, 2007
Unit 2 Diesel Fuel Oil Storage Room 2B, Zone 10.1-2, January 31, 2007
Pre-Fire Plan; Fuel Handling Building, Elevation 401’-0”, Zone 12.1-0, January 31, 2007
Pre-Fire Plan; Fuel Handling Building, Elevation 426’-0”, Zone 12.1-0, January 31, 2007
Fire Protection Report; Section 18.11-0, December 1998
Fire Protection Report; Section 18.11-1, December 1998
Fire Protection Report; Section 18.11-2, December 1998
Fire Protection Report; Figure 2.3-29
Fire Protection Report; Figure 2.3-30
PMID 106774; Disassemble, Clean and Inspect, Assemble Deluge System, August 21, 2007
IR 779116; Scaffold Planks Removed, May 23, 2008
MA-AA-716-025; Scaffold Installation, Modification, and Removal Request Process, Revision 0
Drawing M-1280; Auxiliary Building Ventilation Floor Plan Elevation 373’-6”, Revision U
Drawing M-245; Auxiliary Building Piping Plan Elevation 383’-0”, Revision P
M-603 - Sheet Number 64; Viking Sprinkler System Auxiliary Building Area 1-T1 & Area 1-T2, Basement Elevation 373’-0”, Revision F
2BOSR 7.5.4-2; Unit 2 Diesel Driven Auxiliary Feedwater Pump Monthly Surveillance, Revision 15

Corrective Action Documents as a Result of NRC Inspection

IR 770364; NRC Questioning FP Sprinkler Potential Spray Obstructions, April 30, 2008
IR 775188; NRC Walkdown Items, May 13, 2008
IR 776571; NRC Raised FP Questions During FHB Tour, May 16, 2008
IR 787352; River Screenhouse 0A Diesel Exhaust Piping Penetration Insulation, June 17, 2008
IR 787353; River Screenhouse 0B Diesel Exhaust Piping Penetration Insulation, June 17, 2008
IR 788076; Bird Nest in Horizontal Exhaust, June 19, 2008

Section 1R06: Flood Protection

IR 761585; Door Handwheel is Binding When Door Closes, April 10, 2008
IR 767486; Inappropriate Engineering Involvement in Flooding Risk Issue, April 25, 2008
BAR 0-38-A14; Turbine Building Fire/Oil Sump Flood Level, Revision 5
DCR # 990198; Turbine Building Water Level After Circ. Water Line Break, October, 14, 1999
0BMSRDD-1; Water-Tight Barrier Inspection (CM-6.1.1), Revision 5
WO 836114-12; Remove & Repair Water-Tight Barrier 2DSFS002

Section 1R08: ISI Activities

IR 717257; NRC IN 2007-37; Buildup of Deposits in Steam Generators, January 2, 2008
IR 668998; NRC RIS 2007-20 Primary to Secondary Leakage, September 7, 2007
AT: 00717275-02; Buildup of Deposits in Steam Generators, NRC IN 2007-37
ER-AP-335-1012; Bare Metal Visual Examination of PWR Vessel Penetration and Nozzle Safe-Ends, Revision 3
ER-AP-335-040; Evaluation of Eddy Current Data for Steam Generator Tubing Revision 3
ER-AP-335-039; Multi-frequency Eddy Current Data Acquisition of Steam Generator Tubing, Revision 4
ER-MW-335-1009; Site Specific Performance Demonstration Program, Revision 3
LS-AA-115; Operating Experience Procedure, Revision 11
Byron Unit 1, B1R15 Degradation Assessment and Condition Monitoring Checklist, Revision 0
EXE-UT-68; Ultrasonic Examination of Unit 1 Replacement Steam Generator Main Feedwater Nozzle Inside Radius Section at Braidwood, Revision 2
Westinghouse Data Pkg B1R15-UT-001; Ultrasound Examination of Feedwater Nozzle Inner Radius 1RC-01-BB, N-3-NIR, March 30, 2008
Westinghouse Data Pkg B1R15-PT-001; Penetrant Examination of 1SI03DA-2"/W-09, March 29, 2008
08-11; Evaluation of B1R14 Imbedded Ultrasonic Indication Outside Required Examination Volume, April 1, 2008

Section 1R12: Maintenance Effectiveness (Quarterly)

LER 455-2008-001-00; Unit 2 Emergency Diesel Generators and Auxiliary Feedwater Pump Automatic Start Resulting from a Loss of Offsite Power Due to a Failed Insulator Causing a Differential Phase Overcurrent.
Root Cause Report; Byron Station Unit 2 Loss of Off-Site Power Event, March 25, 2008
NRC Information Notice 98-36; Inadequate or Poorly Controlled, Non-Safety-Related Maintenance Activities Unnecessarily Challenged Safety Systems, September 18, 1998
Drawing No. 6E-2-4419; Three Line Diagram System Auxiliary Transformers 242-1 & 242-2, Revision C

Drawing No. 6E-2-4016D; Relaying & Metering Diagram Differential Relay Transfer Scheme System Auxiliary Transformers 242-1 & 242-2, Revision D
6E-2-4016C; Relaying & Metering Diagram System Auxiliary Transformers 242-1 & 242-2, Revision J
Calibration Data; Attachment 3 HU, HU-1, HU-4 Type Differential relay, March 26, 2008
Nuclear Accident Reporting System (NARS) Form, March 25, 2008
B1R15 Shutdown Risk, March 25, 2008
BOP AP-86; Isolating SAT 242-2 At Power, Revision 9
EC 370080 00; Engineering Evaluation of the SAT 242-1 Testing Requirements Following the Actuation of the Differential Protection for SAT 242-2, March 27, 2008
EPRI TR-112784; Isolated Phase Bus Maintenance Guide, May 1999
Drawing No. 6E-2-4003A; Phasing Diagram Part 1, Revision B
Drawing No. 6E-2-4003B; Phasing Diagram Part 2, Revision C
NES-EIC-17.03; Nuclear Engineering Standards, High Potential Tests, Revision 0
Log No. 08-031; Unit 2 Standing Order, June 13, 2008
IR 772956; Maintenance Rule (A)(1) Determination Required for MP2, May 7, 2008
IR 773419; Work Request to Install Filter Drain in Rubber Boot Seals, May 8, 2008
IR 783134; 0B SX Makeup Pump Needs Reportability Review, June 5, 2008`
Project No. BYR-92592; Failure Analysis of the Byron Auxiliary 242-2, Non-Segregated Bus Duct, Section 15, B Phase Insulator, April 25, 2008
IR 754582; Unit 2 Loss of Off-Site Power, March 25, 2008
IR 754585; Two of Four Fans Not Running on 2B SX Pump Cubicle Cooler, March 25, 2008
IR 754602; SAT 242-2 Phase C Overcurrent, March 25, 2008
IR 755875; Maintenance Rule (A)(2) at Risk Due to Unplanned SAT Outage, March 28, 2008
IR 760354; Bolted Connection on 6.9KV Non Seg Found Loose, April 7, 2008
IR 761246; Non-Seg Bus Duct Inspection, April 9, 2008
IR 762409; Replace Rubber Expansion Boot Around Non-Seg Bus Duct, April 11, 2008
IR 762638; Megger Test UAT 141-1 4KV & 6.9KV, April 12, 2008
IR 768314; Unexpected Alarms – Unit 2 SAT’s, April 27, 2008
IR 768317; SAT 242-2 Phase –A Differential Overcurrent Lockout When SAT Energized, April 27, 2008
IR 774259; SAT Isolation Procedure Differences – Plant and OLR Impacts, May 11, 2008
IR 779699; 0B SX M/U Pump Failed to Run During Low Level Start, May 27, 2008
WO 912183 01; Replace Parker Check Valve at SX M/U Pump Fuel Oil Line, April 29, 2008
MA-AA-716-011; Work Execution & Close Out, Revision 11

Corrective Action Documents as a Result of NRC Inspection

IR 770417; NRC Concern on SAT 242-2 Trip When Energized, April 28, 2008
IR 780732; NRC Requested Past Operability Evaluation – 0B SX M/U Pump, May 29, 2008

Section 1R13: Maintenance Risk Assessments and Emergent Work Evaluation

Unit 2 Risk Configurations, Week of March 31, 2008
Unit 2 Risk Configurations, Week of March 31, 2008, Revision 1
Unit 2 Risk Configurations, Week of March 31, 2008, Revision 2
Unit 2 Risk Configurations, Week of March 31, 2008, Revision 3
Unit 2 Risk Configurations, Week of April 7, 2008
Unit 2 Risk Configurations, Week of April 7, 2008, Revision 1
Unit 2 Risk Configurations, Week of May 5, 2008, Revision 1
Unit 2 Risk Configurations, Week of May 26, 2008, Revision 3

Protected Equipment Log, May 7, 2008
Protected Equipment Log, May 28, 2008
IR 562336-13; License Amendment Implementation Consider License Amendment for RPS/ESFAS Test times and Completion Times Relaxations for Operator Training, September 1, 2007
IR 759929; Clearance Order Returned with Dead Man Switch Still Installed, April 6, 2008
IR 759945; Unplanned Unit 2 Online Risk Orange Condition, April 6, 2008
Unit 1/2 Standing Order 08-011; Technical Specification Amendment 153, February 14, 2008
WO 836114; Replace 1SX034 in B1R15, April 7, 2008
WO 836114 06; Remove/Reinstall Flood Seal 2DSFS003 to Support 1SX034 Valve Replacement
WO 1120558 01; 1SX033 - Remove and Inspect/Rebuild Limitorque Operator and Gear, April 9, 2008
Clearance 63416; EPN 1SX033
Clearance 57893; 1SX034 – De-Term/Re-Term Valve for Replacement
Clearance 57894; 1SX034 – Replace Valve, April 1, 2008
B1R15 OCC Turnover, April 5, 2008 – June 7, 2008
Quick Human Performance Investigation Report; Unplanned Unit 2 On-Line Risk (OLR) Orange Condition, April 7, 2008
EST 08-0242; Abnormal Component Position 1SX033, April 5, 2008
Byron's Archival Operations Narrative Logs, March 31, 2008 to April 7, 2008
B1R15 Shutdown Risk; April 5, 2008 and April 6, 2008
BYR-1SX034; Diagnostic Test Instructions – Control Circuit Changes to Support Testing, April 7, 2008
Draft Unplanned Unit 2 On-Line Risk (OLR) Orange Condition Root Cause Investigation Report
PBI 07-513; Plant Barrier Impairment Permit
WC-AA-101; Attachment 6 Unavailability Guidelines, Revision 14
0B0A PRI-8; Auxiliary Building Flooding Unit 0, Revision 0
1BOA PRI-7; Essential Service Water Malfunction Unit 1, Revision 104
2BOA PRI-7; Essential Service Water Malfunction Unit 2, Revision 105
BB PRA-017.91B; Byron SDP Evaluation of Failure to Conduct a Risk Evaluation Prior to Disabling 1SX033 and 1SX034 Remote Isolation Capability, Revision 0
BOP SX-22; Essential Service Water Leak Isolation, Revision 0
BAR 0PLO1J-9B1; Essential Service Water Pump 2A Leak Detected - Pump Level High, Revision 1
Diagram of Essential Service Water; M-42 Sheet Number 3, Revision AZ
Diagram of Essential Service Water; M-42 Sheet Number 5A &5B Revision AE
Diagram of Essential Service Water; M-42 Sheet Number 1A & 1B, Revision AN
Diagram of Essential Service Water; M-42 Sheet Number 2A & 2B Revision AW

Corrective Action Documents as a Result of NRC Inspection

IR 773344; DC Emergency Light 0LL076E is Malfunctioning, May 8, 2008

Section 1R15: Operability Evaluations

Analysis No. ATD-0111; Containment Flood Level, Revision 013D
Analysis No. BYR2000-180; Available Margin for Miscellaneous Hydrogen Producing Materials in the Byron Unit 1 and 2 Containment Buildings, Revision 8
Calculation No. CN-LIS-00-55; LBL0CA/SBL0CA Evaluation of Revised Containment Data for Byron/Braidwood Units 1 and 2 (CAE/CBE/CCE/ CAE), Revision 0

EC 370179; Machining of Flange Surface of 1B AF Diesel Exhaust Manifold, Revision 0
EC 370163; Operations Evaluation 08-005, 1B/2B AF Diesel Insulation, Revisions 1 & 2
EC 370270; Foreign Material (Scaffold) Potentially Left in Unit 1 Containment for a Cycle, Revision 000
EC 370369; Past Operability of the 1B AF Pump with Respect to Exhaust Manifold Fire, Revision 0
EC 333036; Install Scaffold Saddles on 401 IMB Between SG AD and BC. This EC Incorporates All Permanent Scaffold Storage Requirements for Containment, Revision 000
EC No. 362730; Foreign Material Not Recovered From Unit 1 ECCS Sump Trash Rack Area, Revision 000
EC 363000; Evaluation for Foreign Material Left in Unit 1 Containment, Revision 000
EC 366163 01; OP Evaluation 07-005 Unventable Gas Voids in Containment Recirculation Pump Piping, February 12, 2008
EC Request 147981; DG: Sealant for Exterior of Intake to Head Flange Interface, June 24, 1999
EC Request 072499; DG Intake Manifolds Leaking Air Around Flange, January 12, 1996
EC Request 358726; Evaluate Permanent/Temporary Repair for Oil Leakage Coming from what Appears to be the CAM Housing Gasket Area, February 26, 2003
IR 493593; 2A DG Minor Air Leak on L8 Cylinder Head Intake Flange, May 25, 2006
IR 727020; Unexpected 2C SI Accumulator Level Drop, January 25, 2008
IR 729265; Gas Void UT Exam Results for Unit 2 SI, January 30, 2008
IR 753008; Cause of 1B AF Pump Fire Conditions May Exist on 2B AF Pump, March 21, 2008
IR 753012; During 1B AFW Pump Test an Oil Leak Developed with Flames, March 21, 2008
IR 753383; Starter Motor Shorted during Pump Start, March 23, 2008
Quick Human Performance Investigation Report on IR 753383
IR 755140; 1RH619 Failed Open, March 26, 2008
IR 759028; As Found Results of 1B AF Exhaust Manifolds Out of Spec, April 3, 2008
IR 760408; Insulation in Poor Condition, April 8, 2008
IR 761633; VTIP Information Conflicts with As Built, April 10, 2008
IR 763216; AF System to Remain Yellow in Ship, April 14, 2008
IR 771208; EC's for Equipment Stored in Containment Due to GSI-191, May 2, 2008
IR 775293; Need a WR to Resolve Potential Failure of RH Valves, May 14, 2008
IR 776353; Void Found at 2SI8811A After 2A RH Pump Window, May 16, 2008
IR 756739; Scaffold Left IMB Since B1R14, March 30, 2008
IR 765637; Fires Involving Diesel Engine Exhaust Manifolds, April 21, 2008
IR 779122; Gas Void Discovered After Fill & Vent of 1A RH Suction, May 23, 2008
IR 783173; Delamination Issue with Valve Cover Gasket for AF Diesel, June 5, 2008
WO Task; 934752 01; MM-2DG01KA-24 Month Mechanical Inspection, April 24, 2008
WC-BY-106; Condition Based Monitoring Program, Appendix A, Revision 1
BYR-92045; Evaluation of Exhaust Manifold Gaskets from the Byron 1B AF Pump Diesel Engine, April 7, 2008
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WO 962127 01; 1B AF Pump Emergency Actuation Signal Verification Test, April 12, 2008
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WO 01001347 01; 1AF01PB Comprehensive IST Requirements for the Diesel Driven AF PMP, April 29, 2008
WO 972033; Unit 1 PRT Slow Fill Rate – Inspect 1PW005 During B1R15, March 14, 2008
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IR 768943; Adverse Atmosphere for 1B AF PP Rounds, April 29, 2008
IR 768955; Room Uninhabitable During 1B AF PP Full Flow Test, April 29, 2008
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EP-AA-120F-05; Event Review Checklist, Revision A
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LS-AA-126-1005; 2008 NRC EP Baseline Program Inspection Readiness Assessment, Revision 3
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LIST OF ACRONYMS USED

AC	Alternating Current
AFW	Auxiliary Feed Water
ALARA	As-Low-As-Is-Reasonably-Achievable
ANS	Alert and Notification System
ASME	American Society of Mechanical Engineers
BACC	Boric Acid Corrosion Control
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CS	Containment Spray
CSS	Containment Spray System
CV	Charging Pump
DMBW	Dissimilar Metal Butt Weld
EC	Engineering Change
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
ERO	Emergency Response Organization
EPRI	Electric Power Research Institute
ET	Eddy Current
FPP	Fire Protection Program
GL	Generic Letter
GSI	Generic Safety Issue
ICDF	Incremental Core Damage Frequency
ICDP	Incremental Core Damage Probability
ICDPD	Incremental Core Damage Probability Deficit
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report
ISI	Inservice Inspection
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MRP	Material Reliability Program
NCV	Non-Cited Violation
NDE	Non-destructive Examination
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
OL	Operating License
OOS	Out of Service
PDI	Performance Demonstration Initiative
PI	Performance Indicator
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Assessment
RCS	Reactor Coolant System
RH	Residual Heat Removal
RMA	Risk Management Action
RP	Radiation Protection
SAT	System Auxiliary Transformer
SDP	Significance Determination Process

SG	Steam Generator
SI	Safety Injection
SPAR	Simplified Plant Analysis Risk Model
SX	Essential Service Water System
TI	Temporary Instruction
TLD	Thermoluminescent Dosimeters
TRM	Technical Requirements Manual
TS	Technical Specification
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
URI	Unresolved Item
UT	Ultrasonic Testing
WO	Work Order