UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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LISLE, IL 60532-4352

July 26, 2016

EA–16–125

Mr. Bryan C. Hanson
Senior VP, Exelon Generation Company, LLC
President and CNO, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BYRON STATION, UNITS 1 AND 2 — NRC INTEGRATED INSPECTION REPORT 05000454/2016002; 05000455/2016002 AND EXERCISE OF ENFORCEMENT DISCRETION

Dear Mr. Hanson:

On June 30, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed a quarterly integrated inspection at your Byron Station, Units 1 and 2. On July 12, 2016, the NRC inspectors discussed the results of this inspection with Mr. M. Kanavos and other members of your staff. The enclosed report represents the results of this inspection.

Based on the results of this inspection, the NRC has identified two issues that were evaluated under the risk significance determination process as having very low safety significance (i.e., Green). The NRC has also determined that one of these issues has an associated violation. Because the licensee initiated an issue report to address the violation, it is being treated as a Non-Cited Violation (NCV), consistent with Section 2.3.2 of the Enforcement Policy. Both findings are described in the subject inspection report. Further, inspectors documented licensee-identified violations which were determined to be of very low safety significance in this report. The NRC is treating these violations as NCVs consistent with Section 2.3.2.a of the Enforcement Policy.

A violation of the licensee's current site-specific licensing basis for tornado-generated missile protection was identified. Because this violation was identified during the discretion period discussed in Enforcement Guidance Memorandum 15–002, "Enforcement Discretion for Tornado Missile Protection Noncompliance," and because the licensee implemented compensatory measures, the NRC is exercising enforcement discretion by not issuing an enforcement action for the violation and allowing continued reactor operation.

If you contest the violations or significance of the NCVs, 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 copies to: (1) the Regional Administrator, Region III; (2) the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; and (3) the NRC Resident Inspector at the Byron Station.

In addition, if you disagree with the cross-cutting aspect assignment to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Byron Station.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, “Public Inspections, Exemptions, Requests for Withholding,” of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC’s Public Document Room or from the Publicly Available Records System (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA Jamnes Cameron Acting for/

Eric Duncan, Chief
Branch 3
Division of Reactor Projects

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

Enclosure:
IR 05000454/2016002; 05000455/2016002

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000454; 05000455
License Nos:	NPF–37; NPF–66
Report No:	05000454/2016002; 05000455/2016002
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	Byron, IL
Dates:	April 1, 2016 through June 30, 2016
Inspectors:	J. McGhee, Senior Resident Inspector J. Draper, Resident Inspector C. Hunt, Reactor Engineer S. Bell, Senior Health Physicist G. Edwards, Health Physicist M. Holmberg, Senior Reactor Inspector L. Smith, Reactor Inspector C. Thompson, Resident Inspector, Illinois Emergency Management Agency
Approved by:	E. Duncan, Chief Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY

Inspection Report 05000454/2016002, 05000455/2016002; 04/01/2016 – 06/30/2016; Byron Station, Units 1 and 2; Maintenance Effectiveness; Occupational Radiation Protection.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Two Green findings, one of which had an associated non-cited violation (NCV), were identified. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated February 4, 2015. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process," dated February 2014.

NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

Green. A finding of very low safety significance was identified by the inspectors when, upon identification of a through-wall leak, the licensee declared the structural integrity of Class 3 fire protection piping to be operable, but failed to perform augmented examinations within 30 days as required by American Society of Mechanical Engineers (ASME) Code Case N–513–3. The licensee repaired the leaking pipe, and upon identification by the inspectors, documented the issue in their corrective action program (CAP) as IRs 2639930 and 2652145, and performed the required augmented examinations.

The inspectors determined the performance deficiency was more than minor because, if left uncorrected, the finding had the potential to lead to a more significant safety concern. Specifically, the augmented examinations identified a location where wall thickness measurements were below the acceptance criteria such that the pipe could have ruptured during a seismic event, impacting the functionality of the fire protection system and causing a flooding hazard in the auxiliary building. Because the finding involved an internal flooding hazard, a detailed risk evaluation was performed, which determined the finding to be of very low safety significance. The inspectors determined the finding had a cross-cutting aspect in the Problem Identification and Resolution area of Evaluation [P.2], because the licensee failed to thoroughly evaluate the issue to ensure that the resolution addressed the cause and extent of condition commensurate with the safety significance. Specifically, the licensee failed to complete the N-513-3 evaluation and perform the required extent of condition activities in a timely manner as specified by the ASME Code Case. (Section 1R12.1)

Cornerstone: Occupational Radiation Safety

Green. A finding of very low safety significance and an associated Non-Cited Violation (NCV) of Technical Specification 5.4.1 was self-revealed when an engineer violated a radiation work permit by entering an area that was outside of the scope of the radiation work permit (RWP), which resulted in the engineer receiving an unplanned electronic dosimeter dose rate alarm. After the engineer received the unplanned dose rate alarm,

he immediately exited the area and reported the event to the radiation protection staff. The licensee entered this issue into their CAP as IR 02655195.

The inspectors determined that the performance deficiency was more than minor because the finding impacted the Program and Process attribute of the Occupational Radiation Safety Cornerstone, and adversely affected the cornerstone objective of ensuring adequate protection of worker health and safety from exposure to radiation. Specifically, the engineer, by entering an area that he was not briefed to enter on the radiation work permit, removed a barrier that was intended to prevent workers from receiving unexpected dose. The finding was determined to be of very low safety significance in accordance with Inspection Manual Chapter (IMC) 0609, Appendix C, "Occupational Radiation Safety Significance Determination Process," dated August 19, 2008. The violation was determined to be of very low safety significance (Green) because: (1) it did not involve as-low-as-reasonably-achievable (ALARA) planning or work controls; (2) there was no overexposure; (3) there was no substantial potential for an overexposure; and (4) the ability to assess dose was not compromised. The inspectors determined that the finding had a cross-cutting aspect in the Human Performance area of Challenging the Unknown [H.11] because the individual did not stop when faced with an uncertain condition. Specifically, risks were not evaluated and managed before proceeding. (Section 2RS1.6)

Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

During this inspection period, both Unit 1 and 2 at Byron Station were periodically scheduled to vary electrical output by the grid operator to ramp down up to a few hundred megawatts for short periods to help ease congestion on the transmission system or to support the economic dispatch agreement between Exelon and the grid operator. Unit 1 began the period at full power and operated at scheduled power levels for the entire inspection period. Unit 2 began the period at full power and operated at scheduled power levels until April 5 when the unit began to coast down prior to a scheduled refueling outage. On April 18, Unit 2 was taken offline and refueling outage B2R19 began. The outage ended on May 18, 2016, and the unit reached full power on May 19 after completion of all required testing. Unit 2 operated at scheduled power levels for remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 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.

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. 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:

- Miscellaneous Electrical Equipment Room HVAC (VE); and
- Chilled Water (WO)

This inspection constituted one seasonal adverse weather sample as defined in IP 71111.01–05.

b. Findings

No findings 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:

- Unit 2 chemical and volume control system (CV) during low temperature overpressure (LTOP) alignment in Mode 6;
- 1B auxiliary feedwater (AF) subsystem during 1A AF surveillance testing; and
- 1B CV pump after maintenance.

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, the UFSAR, Technical Specification (TS) requirements, outstanding work orders (WOs), issue 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.

These activities constituted three partial system walkdown samples as defined in IP 71111.04–05.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

During the period of May 4 through May 13, 2016, the inspectors performed a complete system alignment inspection of the Unit 2 Safety Injection (SI) System to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups; 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 WOs 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.

These activities constituted one complete system walkdown sample as defined in IP 71111.04–05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Division 21 engineered safety feature (ESF) switchgear room;
- Division 22 ESF switchgear room;
- Unit 1 414' elevation electrical penetration area;
- Division 12 electrical penetration area;
- 2B CV pump room;
- Unit 2 containment pipe penetration area (Area 7); and
- 2B SI pump room.

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program 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 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. 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 seven quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R08 Inservice Inspection Activities (71111.08)

From April 18, 2016, through May 4, 2016, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the Unit 2 reactor coolant system, steam generator (SG) tubes, emergency feedwater systems, risk-significant piping and components and containment systems.

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

.1 Piping Systems Inservice Inspection

a. Inspection Scope

The inspectors observed and reviewed records of the following non-destructive examinations required by the American Society of Mechanical Engineers (ASME), Section XI Code, and/or Title 10, *Code of Federal Regulations* (CFR), Part 50.55a to evaluate compliance with the ASME Code, Section XI and Section V requirements, and if any indications and defects were detected, to determine whether these were dispositioned in accordance with the ASME Code or an U.S. Nuclear Regulatory Commission (NRC) approved alternative requirement.

- Ultrasonic Testing (UT) of feedwater system pipe welds (2FW87CC–6C32 and 2FW87CC–6C33);
- UT of residual heat removal system pipe weld (2RH01BA–12/C21);
- UT of Safety Injection System pipe weld (2SI06BB–24/C28);
- UT of containment spray system pipe weld (2CS06AA–6/C12); and
- Magnetic Particle examination of main steam system support stanchion weld (2MS07AD–28/E–2).

The inspectors reviewed the following examination records with relevant/recordable conditions/indications identified by the licensee to determine whether acceptance of these indications for continued service was in accordance with the ASME Code Section XI or an NRC approved alternative.

- Dye Penetrant examination of a Main Steam System pipe-to-lug attachment weld 2 MS01AA–30.25 E2) (Reports Nos. B2R18–PT–001 and B2R18–PT–003).

The inspectors reviewed records of the following risk-significant pressure boundary ASME Code Section XI Class 1 welds fabricated since the beginning of the last refuelling outage to determine if the licensee: followed the welding procedure; applied appropriate weld filler material; and implemented the applicable Section XI or Construction Code non-destructive examinations and acceptance criteria. Additionally, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to determine if the weld procedure was qualified in accordance with the requirements of Construction Code and the ASME Code Section IX.

- Install Check Valves in the Auxiliary Feedwater System - Weld No. 19 and 20 (Work Order 001634753–01).

b. Findings

No findings were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

For the Unit 2 vessel head, a bare metal visual examination as well as non-visual examinations were required this outage pursuant to 10 CFR 50.55a(g)(6)(ii)(D).

The inspectors observed portions of the visual examination conducted on the Unit 2 reactor vessel head to determine if the activities were conducted in accordance with the requirements of ASME Code Case N–729–1 and 10 CFR 50.55a(g)(6)(ii)(D). In particular, the inspectors confirmed for a sample of penetration locations that:

- the required visual examination scope/coverage was achieved and limitations (if applicable were recorded) in accordance with the licensee procedures;
- the licensee criteria for visual examination quality and instructions for resolving interference and masking issues were adequate; and
- if indications of potential through-wall leakage were identified, the licensee entered the condition into the CAP and implemented appropriate corrective actions.

The inspectors observed the UT conducted on the Unit 2 reactor vessel head penetrations to determine whether the activities were conducted in accordance with the requirements of ASME Code Case N–729–1 and 10 CFR 50.55a(g)(6)(ii)(D). In particular, the inspectors confirmed for a sample of the head penetration locations that:

- the required examination scope (volumetric and surface coverage) was achieved and limitations (if applicable) were recorded in accordance with the licensee procedures;
- the UT equipment and procedures applied were demonstrated by blind demonstration testing;
- if indications or defects were identified, the licensee documented the conditions in examination reports and/or entered this condition into the CAP and implemented appropriate corrective actions; and
- if indications were accepted for continued service the licensee evaluation and acceptance criteria were in accordance with the ASME Section XI Code, 10 CFR 50.55a(g)(6)(ii)(D) or an NRC-approved alternative.

Based upon the licensee's examination, no new relevant indications were accepted for continued service and no new welded repairs were required for the Unit 2 vessel head penetrations. Therefore, no NRC review was completed for these inspection procedure attributes.

b. Findings

No findings were identified.

.3 Boric Acid Corrosion Control

a. Inspection Scope

The inspectors independently walked down the reactor coolant system loop piping, including the reactor coolant pumps, pressurizer, and emergency core cooling systems within containment to identify boric acid leakage. The inspectors then reviewed the walkdown performed by the licensee to ensure that components with boric acid deposits were identified and entered into the CAP. The inspectors observed these examinations to determine whether the licensee focused on locations where boric acid leaks can cause degradation of safety significant components.

The inspectors reviewed the following licensee evaluations of components with boric acid deposits to determine if the affected components were documented and properly evaluated in the CAP. Specifically, the inspectors evaluated the licensee's corrective actions to determine if degraded components met the component Construction Code and/or the ASME Section XI Code.

- Issue Report (IR) 02387497 – 2RC8037C — 2C Reactor Coolant Loop Drain Valve Leak; and
- IR 02516949 – 2PS9354A — Pressurizer Air Operated Valve.

The inspectors reviewed the following corrective actions related to evidence of boric acid leakage to determine whether 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 02522775 – 2FC02F — Unit 2 Spent Fuel Pit Filter; and
- IR 02517344 – 2CV190 — Injection Isolation Valve.

b. Findings

No findings were identified.

.4 Steam Generator Tube Inspection Activities

a. Inspection Scope

For the Unit 2 SGs, no examination was required pursuant to the Technical Specifications during the current refueling outage. Therefore, no NRC review was completed for this inspection procedure attribute.

b. Findings

No findings 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 corrective action documents reviewed by the inspectors are listed in the Attachment to this report.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On June 28, 2016, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training. The inspectors verified that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and that 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.

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

This inspection constituted one quarterly licensed operator requalification program simulator sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation During Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On April 17, 2016, the inspectors observed operators shutting down Byron Unit 2 from 92 percent power for refueling activities. The inspectors monitored operator manipulation of reactivity controls and significant plant equipment realignment during the shutdown. This was an activity that required heightened awareness. 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 (if applicable);
- correct use and implementation of procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions.

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements.

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

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

- fire protection system; and
- 345 KV switchyard system.

The inspectors reviewed events including those during which ineffective equipment maintenance 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 CAP with the appropriate significance characterization.

This inspection constituted two quarterly maintenance effectiveness samples as defined in IP 71111.12–05.

b. Findings

(1) Failure to Perform ASME Code Case Required Extent of Condition to Identify Unacceptable Piping Flaws

Introduction: A finding of very low safety significance (Green) was identified by the inspectors when the licensee failed to perform augmented examinations within 30 days as required by ASME Code Case N–513.

Description: On March 21, 2014, the licensee identified a through-wall leak on a section of 4-inch piping associated with the fire protection water system in the auxiliary building. The licensee determined that the fire protection water system inside the auxiliary building is safety-related and ASME Section III, Class 3 piping. The licensee's Technical Requirements Manual Limiting Condition for Operation (TLCO) 3.4.f, "Reactor Coolant System Structural Integrity," Condition B, stated that if the structural integrity of one or more ASME Code Class 3 components were not in conformance with the ASME code, the licensee was required to either restore the structural integrity of the affected component to within its limit or isolate the affected component immediately.

Licensee procedure OP–AA–108–115, "Operability Determinations," Step 4.5.9.5 stated that a flaw that was evaluated in accordance with, and meets the acceptance criteria of, Code Case N–513 was acceptable to both ASME and to the NRC. Code Case N–513, which was endorsed by the NRC in Regulatory Guide 1.147, contained actions required by the licensee in order to allow the temporary acceptance of a flaw, including through-wall flaws, in moderate energy Class 2 or 3 piping, without performing a repair or replacement activity. One of these required actions was the performance of an augmented examination to assess degradation of the affected system. This augmented examination required a sample size of at least five of the most susceptible and accessible locations within 30 days of detecting the flaw.

Following the identification of the through-wall leak on March 21, 2014, the licensee declared the structural integrity of the fire protection piping operable pending an N–513 evaluation that was to be documented in an operability evaluation that operations requested from engineering. On March 26, 2014, the licensee determined that an operability evaluation was not appropriate for a Technical Requirements Manual (TRM) issue and cancelled the evaluation. On March 27, 2014, the affected section of piping was isolated, and repairs to the piping were completed on March 31, 2014.

In March 2016, the inspectors questioned the licensee as to what extent of condition was performed following the March 21, 2014, through-wall leak. The licensee determined that they had not performed an extent of condition evaluation and documented the inspectors' questions in IRs 2639930 and 2652145. The licensee selected five locations to perform the augmented examinations to satisfy the extent of condition review requirements of ASME Code Case N–513. Upon performing non-destructive examination on these five locations, on April 27, 2016, the licensee identified areas at one of the locations where the wall thickness was below the acceptance criteria. Upon identification, the license declared the structural integrity of the affected piping inoperable and isolated the affected piping in accordance with TLCO 3.4.f. The licensee also documented the issue in IR 2661892 and expanded the scope of the augmented examinations to include more locations. No additional discrepancies were identified.

Analysis: The inspectors determined that the licensee's failure to implement all the required actions of ASME Code Case N–513–3 within the required timeframe was a performance deficiency. Specifically, when a through-wall leak was identified on ASME Class 3 fire protection piping in the auxiliary building, the licensee declared the structural integrity of the piping operable by applying ASME Code Case N–513–3, but failed to perform the required augmented examination within 30 days of detecting the flaw.

The inspectors determined this finding to be of more than minor significance because, if left uncorrected, it had the potential to lead to a more significant safety concern. Specifically, upon performing the augmented examination, the licensee identified one location where wall thickness measurements were below the acceptance criteria. Had this gone unidentified, the piping could have ruptured during a seismic event, impacting the functionality of the fire protection system and causing a flooding hazard in the auxiliary building.

The inspectors determined that this issue impacted the Initiating Events and Mitigating Systems cornerstones because it constituted an External Events initiator and affected an External Event Mitigation System. Because the finding involved fixed fire protection systems, the inspectors used IMC 0609, Appendix F, "Fire Protection Significance Determination Process," dated September 20, 2013, to evaluate the significance of the finding. Since the reactor was still able to reach and maintain a safe shutdown condition, the finding screened as having very low safety significance (Green). The inspectors also used IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, to address the potential flooding impact of the finding. Using Exhibit 1, "Initiating Events Screening Questions," the inspectors determined that the finding impacted the frequency of an internal flooding initiating event; therefore, a detailed risk evaluation was required.

In accordance with the Byron Station Individual Plant Examination of External Events (IPEEE), all fire protection (FP) piping in the Auxiliary Building (AB) were seismically designed. However, due to the unacceptable flaws (i.e., thickness measurements below acceptable limits) in one area of the FP piping in the AB, the Senior Reactor Analyst (SRA) conservatively assumed that a fire protection piping rupture would occur at the frequency corresponding to a seismically-induced loss of offsite power (LOOP) event. Using guidance from NRC's Risk Assessment Standardization Project (RASP) website, the frequency of a seismically-induced LOOP for Byron Station was 5.28E–5/yr.

Byron had an abnormal operating procedure (AOP) that addressed AB flooding. Procedure 0BOA PRI–8, “Auxiliary Building Flooding,” provided actions to mitigate flooding in the AB. A step in this procedure determined whether the FP system was intact. If leakage was determined to be from FP piping, then the procedure directed an operator to secure the fire pumps and the FP jockey pumps, and then to locate and isolate the leakage in the FP system.

The Human Error Probability (HEP) that operators would fail to secure the fire pumps (in order to terminate the leakage from a FP piping break) prior to AB flooding that would result in all required safety equipment becoming unavailable was determined using the SPAR-H human reliability analysis method (per NUREG/CR–6883). Using SPAR-H, only the Action portion of the task was evaluated to be applicable. The Performance Shaping Factor (PSF) for “Stress” was determined to be “High,” with the other PSFs at a nominal value. This resulted in an HEP to terminate the AB flooding prior to the loss of all required safety systems from a FP break of 2E–3. If AB flooding was not terminated, then a core damage event was assumed to occur. The Exposure Time (ET) for the finding was assumed to be one year, which was the maximum time allowed by the SDP.

Using the above inputs and assumptions, a delta core damage frequency (ΔCDF) was calculated for the issue of unacceptable FP system flaws:

ΔCDF = [Seismic Frequency] x [HEP to Terminate FP Leakage]

= [5.28E–5/yr] x [2.0E–3]

= 1.1E–7/yr

Since the total estimated change in core damage frequency was greater than 1.0E–7/yr, IMC 0609, Appendix H, “Containment Integrity Significance Determination Process,” was used to determine the potential risk contribution due to large early release frequency (LERF). Byron Station is a 4-loop Westinghouse Pressurized Water Reactor (PWR) with a large dry containment. Sequences important to LERF included steam generator tube rupture events and inter-system loss of coolant accident events. These were not the dominant core damage sequences for this finding. Based on the Detailed Risk Evaluation, the SRA determined that the finding was of very low safety significance (Green).

The inspectors determined that this finding had a cross-cutting aspect in the Problem Identification and Resolution area of Evaluation (P.2), because the licensee failed to thoroughly evaluate the issue to ensure that the resolution addressed the cause and extent of condition commensurate with the safety significance. Specifically, the licensee failed to complete the N–513 evaluation and perform the required extent of condition activities in a timely manner as specified by the Code Case, and when these extent of condition inspections were performed, areas with unacceptable wall thickness were discovered, requiring repair.

Enforcement: The inspectors did not identify a violation of regulatory requirements associated with this finding. **(FIN 05000454/2016002–01; 05000455/2016002–01: Failure to Perform ASME Code Case Required Extent of Condition to Identify Unacceptable Piping Flaws).**

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:

- shutdown safety management plan for Byron Unit 2 prior to and during the refueling outage (B2R19);
- emergent failure of 1B CV pump on April 25, 2016; and
- plant status change from Mode 3 to Mode 2 with multiple components inoperable on May 16, 2016.

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 maintenance risk assessments and emergent work control activities constituted three samples as defined in IP 71111.13–05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- non-destructive ultrasonic testing of essential service water pipe 2SX07HA–20” indicated below minimum wall thickness requirements;
- 1B AF pump adverse oil temperature trend during extended run;
- relay wiring discrepancy with instrument inverter 212; and
- a gas void identified in SI piping during UT exam.

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 reviewed a sample of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

This operability inspection constituted four samples as defined in IP 71111.15–05.

b. Findings

No findings were identified.

.2 Licensee Implementation of Enforcement Guidance Memorandum 15–002, "Enforcement Discretion for Tornado-Generated Missile Protection Noncompliance"

On June 10, 2015, the NRC issued Regulatory Issue Summary (RIS) 2015–06, "Tornado Missile Protection," focusing on the requirements regarding tornado-generated missile protection and required compliance with the facility-specific licensing basis. The RIS also provided examples of noncompliance that had been identified through different mechanisms and referenced enforcement guidance memorandum (EGM) 15–002 which was also issued on June 10, 2015. The EGM provided guidance to allow the NRC staff to exercise enforcement discretion when an operating power plant licensee did not comply with the current licensing basis for tornado-generated missile protection. Specifically, the discretion applied to SSCs declared inoperable resulting in TS LCOs that would require a reactor shutdown or mode change if the licensee could not meet the required actions within the TS completion time. The discretion allowed the licensee to re-establish operability through compensatory measures and established criteria for continued operation of the facility as longer term corrective actions were implemented. The EGM stated that the bounding risk analysis performed for this issue concluded that this issue was of low risk significance and, in Byron's case, provided for enforcement discretion of up to three years from the date of issuance of the EGM. However, the EGM did not provide licensees with enforcement discretion for any related underlying technical violations; and moreover, the EGM specifically requires that any associated underlying technical violation(s) be assessed through the enforcement process.

Appendix A to 10 CFR Part 50, General Design Criteria for Nuclear Power Plants (GDC), Criterion 4, "Environmental and Dynamic Effects Design Basis," stated in part that SSCs important to safety shall be adequately protected against dynamic effects including missiles. On May 25, 2016, the licensee initiated IR 02673848, identifying a nonconforming condition of Criterion 4. Specifically, multiple locations were identified in the refueling water storage tank (RWST) roof hatches and in the L-line wall above the 451' elevation (separating the turbine building from the Class I auxiliary building) where SSCs were not adequately protected from tornado-generated missiles. The licensee declared multiple SSCs inoperable and promptly implemented compensatory measures designed to reduce the likelihood of tornado-generated missile effects. The inspectors reviewed the licensee's compensatory measures that included:

- review and revision of procedures for a tornado watch and a tornado warning to provide additional instructions for operators preparing for tornados and/or high winds, and a potential loss of SSCs vulnerable to the tornado missiles;
- confirmation of readiness of equipment and procedures dedicated to the Diverse and Flexible Coping Strategy (FLEX);
- verification that training was up to date for individuals responsible for implementing preparation and response procedures; and
- establishment of a heightened station awareness and preparedness relative to identified tornado missile vulnerabilities.

The condition was reported to the NRC as Event Notice (EN) 51958 as an unanalyzed condition and potential loss of safety function. The licensee documented the inoperability of the SSCs and the affected TS LCO conditions in the CAP and in the control room operating log. The shift manager notified the NRC resident inspector of implementation of EGM 15–002, and documented the implementation of the compensatory measures to establish the SSCs "operable but nonconforming" prior to expiration of the LCO required action. The enforcement discretion was applied to the required shutdown actions of the following TS LCOs for both units:

- TS 3.0.3, General Shutdown LCO (cascading or by reference from other LCOs)
- TS 3.3.7, "Control Room Ventilation (VC) Filtration System Actuation Instrumentation";
- TS 3.5.2, "ECCS – Operating";
- TS 3.5.4, "Refueling Water Storage Tank (RWST)";
- TS 3.6.6, "Containment Spray and Cooling Systems";
- TS 3.7.9; "Ultimate Heat Sink";
- TS 3.7.10, "Control Room Ventilation (VC) Filtration System";
- TS 3.7.11, "Control Room Ventilation (VC) Temperature Control System";
- TS 3.8.4, "DC Sources – Operating";
- TS 3.8.7, "Inverters – Operating"; and
- TS 3.8.9, "Distribution Systems – Operating".

The inspectors' review addressed the material issues in the plant, and whether the measures were implemented in accordance with the guidance documentation for the EGM. The inspectors also evaluated whether the measures as implemented would function as intended and were properly controlled. The licensee implemented actions to track the more comprehensive actions to resolve the nonconforming conditions within the required 60 days. These comprehensive actions were to remain in place until permanent repairs were completed, which for Byron were required to be completed in three years, or until the NRC dispositioned the non-compliance in accordance with a method acceptable to the NRC such that discretion was no longer needed.

The inspectors did not review the underlying circumstances that resulted in the TS violations. As stated in the EGM guidance, violations of other requirements, including 10 CFR 50 Appendix A, Criterion 4, which may have contributed to the TS violations, would be evaluated independently of the EGM implementation.

This operability inspection constituted a partial sample as defined in IP 71111.15–05 since all corrective actions to support continued operability and resolution of the nonconforming conditions had not been identified. These actions and any underlying

technical violations will be addressed with the completion of this inspection sample and documented in a future NRC Inspection Report.

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following plant modifications:

- Temporary Configuration Change Package (TCCP) 404997; Remove Auxiliary Feedwater Diesel Air Intake Elbow and Blank Off Turbine Building Air Intake;
- Engineering Change 400682, "Unit 2 Reactor Vessel Closure Head Penetration Ultra High Pressure Cavitation Peening"; and
- WO 602804, "Install Equipment for Temp Feed to 2FC01P per MA–BY–726–001."

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the UFSAR, and the TSs to verify that the modifications did not affect the operability or availability of the affected systems. The inspectors observed ongoing and completed work activities to ensure that the modifications were installed as directed and consistent with the design control documents; the modifications operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. The inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modifications with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modifications in place could impact overall plant performance.

1. TCCP404997 was previously discussed in NRC Inspection Report 05000454(455)/2016001 as a partial sample. Additional questions regarding the impact of a fire in the auxiliary building on the auxiliary feedwater diesel driven pumps were discussed at the end of the inspection period, which required the inspection to continue into the second quarter of 2016. The inspectors reviewed the licensee's evaluation of the impact of a potential fire in the auxiliary building on the AF system and safe shutdown operations. The licensee implemented compensatory actions in accordance with the Fire Protection Report and the plant fire barrier impairment procedure that addressed the equipment configuration. Procedures and processes remained in place to ensure that the assumptions in the report could be implemented without impacting the safe shutdown analysis.

2. In EC 400682, the licensee approved application of a water jet cavitation peening process for the Byron Unit 2 reactor vessel closure head penetration nozzles and J-groove welds. This process was designed to impart a compressive residual stress to the surface of the penetration nozzle and weld materials susceptible to primary water stress corrosion cracking (PWSCC) and was intended to diminish the potential for future PWSCC induced cracks and associated leakage. The licensee expected the peened nozzles to result in a reduction in cumulative dose/exposure associated with performing future reactive nozzle repairs caused by PWSCC. The inspectors

previously completed a review of the proposed design configuration change and associated 10 CFR 50.59 safety evaluation No. 6G–15–002 against the design basis, as documented in NRC Inspection Report 05000454/2015004; 05000455/2015004.

During the Byron Unit 2 refueling outage, the inspectors observed application of the peening process for a sample of the J-groove welds and nozzle outside and inside diameter surfaces to determine if:

- the desired scope of area subject to peening was achieved and whether limitations were recorded in accordance with the licensee procedures; and

- the peening equipment configuration was controlled and process essential variables were maintained consistent with the vendor basis documents that had been demonstrated to provide the desired depth of compressive surface residual stress through mockup testing.

The inspectors observed the high pressure jet/bubble cloud at the peening toolhead impacting vessel head surfaces from a camera mounted within the vendor tooling and noted that the peening process removed deposits and oxide layers from the J-groove weld and nozzle outside diameter surfaces resulting in a “shiny” surface relative to the surrounding darker surfaces (unpeened condition). The inspectors also observed that the essential peening process variables were maintained and controlled consistent with the peening vendor procedures and basis documents. The peening vendor generated a data report for each nozzle location that it intended to provide to the licensee as a record of the extent of the peening operation, which included toolhead positions for each control axis. These data reports did not contain sufficient information for the inspectors to independently confirm that the desired scope of area subject to peening was achieved. Instead, the licensee intended to rely on the vendor’s verifications for the toolhead motion profile program configuration to ensure the desired extent of surface area was remediated by the peening process. The licensee was unable to complete peening of the inside diameter surface for nozzles 68, 69, 74, 75, and 77 because the vendor tooling could not be adequately sealed to maintain the backpressure necessary to peen these nozzles.

After vessel reassembly, inspectors reviewed the results of the post modification acceptance pressure test of the Unit 2 reactor vessel head and subsequent rod drop testing.

The reviews constituted three complete modification inspection samples as defined in IP 71111.18–05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- 2AF004A failed to close when required;
- 1B centrifugal charging pump motor bearing replacement;
- 2CC9486 local leak rate test (LLRT) following failed as-found LLRT;
- 2B centrifugal charging pump motor disassembly and inspection;
- Unit 2 automated rod drop timing test following water jet cavitation peening of reactor vessel head penetration nozzles;
- 1SD005D stroke time test, position indication test, and leakage test following actuator rebuild;
- 2PA20JA control cabinet primary power supply replacement; and
- 1D main steam isolation valve accumulator oil pump unable to control accumulator pressure.

These activities were selected based upon the SSCs impact to risk. The inspectors evaluated these activities for the following: 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 Part 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 CAP and that the problems were being corrected commensurate with their importance to safety.

This inspection constituted eight post-maintenance testing samples as defined in IP 71111.19–05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Risk Management Profile including the outage risk profile and contingency plans for the Unit 2 refueling outage (RFO), conducted April 18 – May 18, 2016, 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 RFO, 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 Risk Management Profile 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;
- installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error;
- controls over the status and configuration of electrical systems to ensure that TS and Outage Risk Management Profile 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;
- maintenance of secondary containment as required by TS;
- licensee fatigue management, as required by 10 CFR 26, Subpart I;
- refueling activities, including fuel handling;
- startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the primary containment to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing; and
- licensee identification and resolution of problems related to RFO activities.

This inspection constituted one RFO sample as defined in IP 71111.20–05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 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:

- 2BOSR 8.1.11–1, Unit Two 2A Diesel Generator Sequencer Test (routine);
- 2BOSR 6.1.1–12, Unit Two Primary Containment Type C Local Leakage Rate Tests and IST Tests of Component Cooling System (ISO Valve);
- 2BVSR 7.1.1–1, Unit 2 Main Steam Safety Valves Operability Test (routine);
- 1BOSR 5.5.8.CC.5–2c, Unit One Comprehensive Inservice Testing (IST) Surveillance Requirements for Component Cooling Pump 1CC01PB (IST); and
- 1BOSR 5.5.8.AF.5–1b, Unit One Group B Inservice Testing (IST) Requirements for Motor Driven Auxiliary Feedwater Pump 1AF01PA (IST).

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, sufficient to demonstrate operational readiness, and consistent with the system design basis;
- was plant equipment calibration correct, accurate, and properly documented;
- were as-left setpoints within required ranges; and was the calibration frequency in accordance with TSs, the UFSAR, plant procedures, and applicable commitments;
- was measuring and test equipment calibration current;
- was the test equipment used within the required range and accuracy, and were applicable prerequisites described in the test procedures satisfied;
- did test frequencies meet TS requirements to demonstrate operability and reliability;
- were tests performed in accordance with the test procedures and other applicable procedures;
- were jumpers and lifted leads controlled and restored where used;
- were test data and results accurate, complete, within limits, and valid;
- was test equipment removed following testing;
- where applicable for IST activities, was testing performed in accordance with the applicable version of Section XI of the ASME Code and were reference values consistent with the system design basis;
- was the unavailability of the tested equipment appropriately considered in the PI data;
- where applicable, were test results not meeting acceptance criteria addressed with an adequate operability evaluation or was the system or component declared inoperable;

- where applicable for safety-related instrument control surveillance tests, was the reference setting data accurately incorporated into the test procedure;
- was equipment returned to a position or status required to support the performance of its safety functions following testing;
- were problems identified during the testing appropriately documented and dispositioned in the licensee's CAP;
- where applicable, were annunciators and other alarms demonstrated to be functional and were setpoints consistent with design requirements; and
- where applicable, were alarm response procedure entry points and actions consistent with the plant design and licensing documents.

This inspection constituted two routine surveillance testing samples, two in-service test samples, and one containment isolation valve sample as defined in IP 71111.22, Sections–02 and–05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on May 25, 2016, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the Main Control Room and Technical Support Center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the CAP.

This emergency preparedness drill inspection constituted one emergency preparedness (EP) drill sample as defined in IP 71114.06–06.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

.1 Radiological Hazard Assessment (02.02)

a. Inspection Scope

The inspectors assessed the licensee's current and historic isotopic mix, including alpha emitters and other hard-to-detect radionuclides. The inspectors evaluated whether survey protocols were reasonable to identify the magnitude and extent of the radiological hazards.

The inspectors determined if there have been changes to plant operations since the last inspection that may have resulted in a significant new radiological hazard for onsite individuals. The inspectors evaluated whether the licensee assessed the potential impact of these changes and implemented periodic monitoring, as appropriate, to detect and quantify the radiological hazard. The inspectors reviewed the last two radiological surveys from selected plant areas and evaluated whether the thoroughness and frequency of the surveys were appropriate for the given radiological hazard.

The inspectors conducted walkdowns of the facility, including radioactive waste processing, storage, and handling areas to evaluate material conditions and performed independent radiation measurements as needed to verify conditions were consistent with documented radiation surveys.

The inspectors assessed the adequacy of pre-work surveys for select radiologically risk-significant work activities.

The inspectors evaluated the Radiological Survey Program to determine if hazards were properly identified. The inspectors discussed procedures, equipment, and performance of surveys with radiation protection staff and assessed whether technicians were knowledgeable about when and how to survey areas for various types of radiological hazards (i.e., hot particles, alpha emitters, airborne radioactivity).

The inspectors reviewed work in potential airborne areas to assess whether air samples were being taken appropriately for their intended purpose and reviewed various survey records to assess whether the samples were collected and analyzed appropriately. The inspectors also reviewed the licensee's program for monitoring contamination which has the potential to become airborne.

These inspection activities constituted one sample as defined in Inspection Procedure (IP) 71124.01–05.

b. Findings

No findings were identified.

.2 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors reviewed select radiation work permits (RWPs) used to access high radiation areas and evaluated the specified work control instructions or control barriers. The inspectors also assessed whether workers where made aware of the work instructions and area dose rates.

The inspectors reviewed electronic alarming dosimeter dose and dose rate alarm setpoint methodology. For selected electronic alarming dosimeter occurrences, the inspectors assessed the worker's response to the alarm, the licensee's evaluation of the alarm, and any follow-up investigations.

The inspectors reviewed the licensee's methods for informing workers of changes in plant operations or radiological conditions that could significantly impact their occupational dose.

The inspectors reviewed the labeling of select containers of licensed radioactive material that could cause unplanned or inadvertent exposure to workers.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

.3 Contamination and Radioactive Material Control (02.04)

a. Inspection Scope

The inspectors observed locations where the licensee monitors material leaving the radiologically controlled area and assessed the methods used for control, survey, and release of material from these areas. As available, the inspectors observed health physics personnel surveying and releasing material for unrestricted use.

The inspectors observed workers leaving the radiologically controlled area and assessed their use of tool and personal contamination monitors and reviewed the licensee's criterial for use of the monitors.

The inspectors assessed whether instrumentation was used at its typical sensitivity levels based on appropriate counting parameters or whether the licensee had established a de facto release limit.

The inspectors selected several sealed sources from the licensee's inventory records and assessed whether the sources were accounted for and verified to be intact. The inspectors also evaluated whether any transactions, since the last inspection, involving nationally tracked sources were reported in accordance with Title 10 of the *Code of Federal Regulations*, Part 20.2207.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

.4 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

The inspectors evaluated ambient radiological conditions during tours of the facility. The inspectors assessed whether the conditions were consistent with applicable posted surveys, RWPs, and worker briefings.

The inspectors evaluated the adequacy of radiological controls, such as required surveys, radiation protection job coverage, and contamination controls. The inspectors evaluated the licensee's use of electronic alarming dosimeters in high noise areas as high radiation area monitoring devices.

The inspectors assessed whether radiation monitoring devices were placed on the individual's body consistent with licensee procedures. The inspectors assessed whether the dosimeter was placed in the location of highest expected dose or that the licensee properly employed an NRC approved method of determining effective dose equivalent.

The inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel in high radiation work areas with significant dose rate gradients.

For select airborne area RWPs, the inspectors reviewed airborne radioactivity controls and monitoring, the potential for significant airborne levels, containment barrier integrity, and temporary filtered ventilation system operation.

The inspectors examined the licensee's physical and programmatic controls for highly activated or contaminated materials stored within pools and assessed whether appropriate controls were in place to preclude inadvertent removal of these materials from the pool.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

.5 High Radiation Area and Very-High Radiation Area Controls (02.06)

a. Inspection Scope

The inspectors observed posting and physical controls for high radiation areas and very-high radiation areas to assess adequacy.

The inspectors conducted a selective inspection of posting and physical controls for high radiation areas and very-high radiation areas to assess conformance with performance indicators.

The inspectors reviewed procedural changes to assess the adequacy of access controls for high and very-high radiation areas to determine whether procedural changes substantially reduced the effectiveness and level of worker protection.

The inspectors assessed the controls the high radiation areas greater than 1 rem/hour and areas with the potential to become high radiation areas greater than 1 rem/hour for compliance with TS and procedures.

The inspectors assessed the controls for very-high radiation areas and areas with the potential to become very-high radiation areas. The inspectors also assessed whether individuals were unable to gain unauthorized access to these areas.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

.6 Radiation Worker Performance and Radiation Protection Technician Proficiency (02.07)

a. Inspection Scope

The inspectors observed radiation worker performance and assessed their performance with respect to radiation protection work requirements, the level of radiological hazards present, and radiation work permit controls.

The inspectors assessed worker awareness of electronic alarming dosimeter set points, stay times, or permissible dose for radiologically significant work as well as expected response to alarms.

The inspectors observed radiation protection technician performance and assessed whether the technicians were aware of the radiological conditions and radiation work permit controls and whether their performance was consistent with training and qualifications for the given radiological hazards.

The inspectors observed radiation protection technician performance of radiation surveys and assessed the appropriateness of the instruments being used, including calibration and source checks.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

Introduction: A self-revealed finding of very low safety significance (Green) and an associated non-cited violation (NCV) of Technical Specification 5.4.1 was identified when an engineer violated a RWP by entering an area that was outside the scope of the RWP.

Description: On April 13, 2016, the Radiation Protection staff provided an RWP brief to an engineer that was performing a VT2 Inspection in what is known as “Area 7” in the facility. RWP BY–0–16–00123, Revision 01, specified that a Radiation Protection brief was required prior to accessing areas greater than seven feet. The engineer informed the Radiation Protection staff of the areas that the he would be inspecting and based on this information, it was determined that a high radiation area brief would not be required. During the Radiation Protection brief, the Radiation Protection Technician informed the engineer that he would need to avoid Penetration 41, which was the Chemical and Volume Control System letdown line. Penetration 41 was posted as a high radiation area based on surveys that were conducted. When presented with this information by the Radiation Protection Technician, the engineer informed the technician that his travel path would be near Penetration 54 to identify the line that was needed for the VT2 Inspection. When this portion of the VT2 Inspection was completed, the engineer informed the Radiation Protection Technician that he would climb down to elevation 364’, traverse past the transfer canal, and continue to the other side of the canal while avoiding Penetration 41.

During the VT2 Inspection, the engineer climbed off the platform, which is past the hand railing and on to a number of 3-inch unistruts. This inaccessible area, located near Penetration 53 and adjacent to Penetration 41 was a high radiation area at the time. The Radiation Protection Staff considered this area past the hand railing to be inaccessible and did not perform routine surveys there. Factors that led to the Radiation Protection Staff declaring that this area was inaccessible included the area in question being approximately 25–30 feet from ground level and the area being comprised of unistruts that were not designed to be walked on without proper fall protection. While the engineer was performing tours in this overhead area (near the Chemical and Volume Control System line), he received an unplanned dose rate alarm. The unplanned dose rate alarm was 142 mrem/hour with an alarm set point of 100 mrem/hour. The engineer immediately exited the area upon receiving the unplanned dose rate alarm and reported to the Radiation Protection Staff. The engineer had a cumulative dose of 2.9 mrem from this entry.

Analysis: The inspectors determined that the engineer’s failure to comply with the requirements that were stated in the RWP were within the licensee’s ability to foresee and correct and should have been prevented, therefore constituting a performance deficiency.

The performance deficiency was determined to be more than minor in accordance with IMC 0612, Appendix B, “Issue Screening,” because the performance deficiency impacted the Program and Process attribute of the Occupational Radiation Safety Cornerstone, and adversely affected the cornerstone objective of ensuring adequate protection of worker health and safety from exposure to radiation. The engineer entering an area that he was not briefed to enter on the RWP removed a barrier intended to prevent workers from receiving unexpected dose.

The finding was determined to be of very low safety significance (Green) in accordance with IMC0609, Appendix C, “Occupational Radiation Safety Significance Determination Process,” dated August 19, 2008, because: (1) it did not involve ALARA planning or work controls; (2) there was no overexposure; (3) there was no substantial potential for an overexposure; and (4) the ability to assess dose was not compromised.

The inspectors concluded that the cause of the finding involved a cross-cutting component in the Human Performance area of Challenging the Unknown because the individual did not stop when faced with an uncertain condition. Risks were not evaluated and managed before proceeding. Specifically, the engineer proceeded into an area that he was not briefed to enter which contained unknown dose rates. [H.11]

Enforcement: TS 5.4.1 requires that written procedures shall be established, implemented and maintained covering activities contained in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Procedures specified in Regulatory Guide 1.33 include radiation protection procedures for an RWP. In particular, RWP BY–0–16–00123, Revision 01, specified that a Radiation Protection brief was required prior to accessing areas greater than seven feet.

Contrary to the above, on April 13, 2016, an engineer entered into an area greater than seven feet that was not discussed in the RWP briefing specified by RWP BY-0-16-00123 and Regulatory Guide 1.33, Appendix A, as required by TS 5.4.1. This caused the engineer to receive an unplanned dose rate alarm. Upon receiving the dose rate alarm, the engineer exited the area and immediately reported to the Radiation Protection Staff. Because this violation was of very low safety significance and was entered into the licensee's CAP as IR 02655195, this violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy. **(NCV 05000454/2016002–02; 05000455/2016002–02: Failure to Comply With Radiation Work Permit Requirements Resulting In an Unplanned Dose Rate Alarm)**

.7 Problem Identification and Resolution (02.08)

a. Inspection Scope

The inspectors assessed whether problems associated with radiological hazard assessment and exposure controls were being identified at an appropriate threshold and were properly addressed for resolution. For select problems, the inspectors assessed the appropriateness of the corrective actions. The inspectors also assessed the licensee's program for reviewing and incorporating operating experience.

The inspectors reviewed select problems related to human performance errors and assessed whether there was a similar cause and whether corrective actions taken resolve the problems.

The inspectors reviewed select problems related to radiation protection technician error and assessed whether there was a similar cause and whether corrective actions taken resolve the problems.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

2RS2 Occupational As-Low-As-Reasonably-Achievable Planning and Controls (71124.02)

.1 Problem Identification and Resolution (02.06)

a. Inspection Scope

The inspectors reviewed self-assessments and/or audits performed of the ALARA Program and determined if these reviews identified problems or areas for improvement.

The inspectors assessed whether problems associated with ALARA planning and controls were being identified by the licensee at an appropriate threshold and properly addressed for resolution.

These inspection activities constituted one sample as defined in IP 71124.02–05.

b. Findings

No findings were identified.

2RS3 In-Plant Airborne Radioactivity Control and Mitigation (71124.03)

.1 Problem Identification and Resolution (02.05)

a. Inspection Scope

The inspectors assessed whether problems associated with the control and mitigation of in-plant airborne radioactivity were being identified by the licensee at an appropriate threshold and were properly addressed for resolution. Additionally, the inspectors evaluated the appropriateness of the corrective actions for selected problems involving airborne radioactivity documented by the licensee.

These inspection activities constituted one sample as defined in IP 71124.03–05.

b. Findings

No findings were identified.

2RS4 Occupational Dose Assessment (71124.04)

.1 Problem Identification and Resolution (02.06)

a. Inspection Scope

The inspectors assessed whether problems associated with occupational dose assessment were being identified by the licensee at an appropriate threshold and were properly addressed for resolution. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee involving occupational dose assessment.

These inspection activities constituted one sample as defined in IP 71124.04–05.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Security

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures performance indicator (PI) for Byron Unit 1 and Unit 2 for the period from the second quarter of 2015 through the first quarter of 2016. To determine the accuracy of the data reported during those periods, guidance contained in Nuclear Energy Institute (NEI) 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, and NUREG–1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," was used. The inspectors reviewed the licensee's operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, IRs, and event reports the period of April 1, 2015, through March 31, 2016, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator.

This inspection constituted two safety system functional failure samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the Reactor Coolant System (RCS) Leakage PI for Unit 1 and Unit 2 for the period from the second quarter of 2015 through the first quarter of 2016. To determine the accuracy of the data reported during those periods, guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, was used. The inspectors reviewed the licensee's operator logs, RCS leakage tracking data, IRs, event reports, and NRC integrated inspection reports for the period of April 1, 2015, through March 31, 2016, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the data collected or transmitted for this indicator.

This inspection constituted two reactor coolant system leakage samples as defined in IP 71151–05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Items Entered into the Corrective Action Program

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 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: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; 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.

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 Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection 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 were identified.

.3 Semi-Annual Trend Review

a. Inspection 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 6-month period of December 2015 through June 2016, 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.

Two examples of a failure to implement engineering reviews of maintenance activities were identified in February of 2016. In addition, multiple examples of a failure to complete programmatically required activities within the required frequency were identified in the month of April. Although these performance deficiencies were evaluated to not be more than minor in the SDP process, the examples represented a potential negative trend in tracking the execution of programmatic controls and reference level procedure usage during the period of increased activity prior to and during the refueling outage. In addition to the findings included in Section 1R12 and 2RS1.6, the following examples supported a potential adverse trend in ensuring procedurally required activities were completed within the required time period:

- Two IRs were written that identified equipment installed under a work document that exceeded the procedural limit of 90 days with having a 50.59 safety screening performed. On February 26, 2016, IR 02632168 documented a non-permanent scaffold that was installed longer than the 90-day limit listed in MA–AA–716–025, "Scaffold Installation, Modification, and Removal Request Process." On February 25, 2016, a chart recorder was installed on a pressure control circuit to support troubleshooting and was installed longer than the 90-day limit listed in CC–AA–112, "Temporary Configuration Control Changes." In both cases, the 50.59 screening was promptly performed to allow the equipment to remain installed and no safety evaluation was required. The inspectors concluded that the issue was similar to IMC 0612, Appendix E "Examples of Minor Issues", Example 3.a because the failure to implement the requirement had no safety impact.
- On April 3, 2016, the licensee discovered that the weekly (once per seven days) surveillance requiring verification of ESF onsite power distribution was not completed within the 125 percent required frequency. The operating crew subsequently performed the surveillance satisfactorily within the time specified in Surveillance Requirement 3.0.3 for a missed surveillance. Since the surveillance passed when performed and the issue was entered into the CAP as

IR 022650149 when the condition was recognized, the violation was evaluated as similar to IMC 0612, Appendix E “Examples of Minor Issues”, Example 4.l and determined to be not more than minor because the surveillance test performance was within the time specified in SR 3.0.3 and the surveillance passed when performed. Corrective actions included modifying the turnover sheet to require a review of the critical surveillance book at turnover to ensure the operators were aware of any surveillances approaching the late date. The changes were communicated to the operating supervisors and management observations were conducted to reinforce the importance of schedule adherence.

- On April 27, 2016, operators identified that a required surveillance to measure leakage from the containment emergency hatch was not performed on April 13, because the periodicity requirement was not interpreted correctly by the licensee staff. The surveillance was performed satisfactorily on April 16, 2016, (beyond the 125percent periodicity). Since the surveillance passed when performed and the issue was entered into the CAP as IR 02661939 when the condition was recognized, the inspectors concluded that the violation was similar to IMC 0612, Appendix E “Examples of Minor Issues”, Example 4.l and determined to be not more than minor because the leak test performance was timely and the surveillance passed when performed. Corrective actions included clarifying procedural guidance for the frequency of performance and communicating requirements to the staff.
- On April 27, 2016, chemistry technicians identified that the weekly anion and sodium analysis for the Unit 2 condensate storage tank (CST) was not performed for the week of April 18, although other required analyses for the CST were completed. The analysis was performed on April 28, and all parameters were within specification. The failure to perform the analysis to comply with CY–AP–120–240, “Condensate Storage Tank Chemistry,” was entered into the CAP as IR 02662566 and the inspectors concluded the issue was similar to IMC 0612, Appendix E “Examples of Minor Issues”, Example 3.d because the failure to implement the requirement had no safety impact and the sample delay was not significant. Corrective actions included a review of the use of scheduling tools with licensee staff.

This review constituted one semi-annual trend inspection sample as defined in IP 71152–05.

b. Findings

No findings were identified.

.4 Annual Follow-up of Selected Issues: Licensee Management and Oversight of Chicago Bridge and Iron Contract Employees

a. Inspection Scope

The inspectors and licensee staff identified several issues with contractor performance during the October 2015 refueling outage on Unit 1 and planned an in-depth review as part of the annual performance review of station performance performed in accordance with IMC 0305, “Operating Reactor Assessment Program”. Consequently, the inspectors performed a review of contractor management and oversight during the Unit 2 outage and post-outage time frames. The inspection focused on activities performed by

Chicago Bridge & Iron (CB&I) since these represented the majority of the contract employees performing risk-significant maintenance. CB&I completed several significant activities during the outage, including steam generator bowl drain modifications, a condensate booster pump replacement, instrument bus inverter constant voltage transformer replacements, a reactor containment fan cooler motor replacement, main turbine electro-hydraulic control system skid modifications, and support for the reactor head penetration water peening project. On-line work performed by CB&I contract employees included normal service water strainer valve replacement with a linestop, and reactor pressurizer power-operated relief valve wiring modifications.

The inspectors reviewed documented management observations by the licensee, main control room logs, and items identified in the CAP. In-field observations of contractor work activities were conducted during the period to ensure that managers and supervisors were in the field reinforcing expectations for safety, procedure compliance, and identification of degraded or non-conforming conditions. The inspectors selected the following CAP document for in-depth review:

- IR 02667024; B2R19 CB&I Performance Review Roll-up

As appropriate, the inspectors verified the following attributes during the review of the licensee's corrective actions for the above IR and other related documentation:

- complete and accurate identification of the problem in a timely manner; commensurate with its safety significance and ease of discovery;
- consideration of the extent of condition, generic implications, common cause, and previous occurrences;
- evaluation and disposition of operability/functionality/reportability issues;
- classification and prioritization of the resolution of the problem commensurate with safety significance;
- identification of the causes of the problems;
- completion of corrective actions in a timely manner commensurate with the safety significance of the issue; and
- communication of lessons learned to appropriate organizations.

While instances of noncompliance with procedure or work instructions were identified in the documents reviewed, the inspectors concluded that these issues were evaluated individually as not more than minor and the corrective actions identified in the IR were appropriate to the circumstances. The inspectors concluded that corrective actions for deficiencies identified in the previous outage period were effectively implemented and oversight of contracted work improved. Issues identified during work activities were promptly entered in the CAP and appropriately evaluated.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152–05.

b. Findings

No findings were identified.

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

.1 Notification of Unusual Event Declared Due to Excessive Unidentified Leakage During Unit 2 Plant Startup

On May 15, 2016, with Unit 2 shutdown and in Mode 3, operators raised temperature and pressure to perform the startup Mode 3 walkdown to inspect for reactor coolant system (RCS) leakage, and excess letdown had been aligned to the primary through the Loop "A" drain line.

Event Chronology:

Time	Activity
0842	Operators aligned both excess letdown heat exchangers to the RCS for a pressure test (Procedure identified flowpath from the RCS was through manual loop drain 2RC8039A and air-operated loop drain 2RC8037A to the letdown heat exchangers.)
1025	Primary pressure reached 2235 pounds per square inch gauge (psig) and 540 degrees Fahrenheit (°F).
1030	Significant change in Reactor Coolant Drain Tank (RCDT) level and pressure occurred (This information was recovered from computer data after the event.)
1034	Reactor Vessel Flange Temperature High Leakoff alarm in main control room. Containment Drain Leak Detection Flow High alarm, Reactor Coolant Drain Tank (RCDT) high temperature alarm and RCDT high pressure alarm reported from the radwaste operator.
1037	RCDT temperature indication reached maximum scale (250°F) and pressure (40 psig).
1040	Operators stabilized plant conditions to calculate leak rate and entered abnormal operating procedure 2BOA PRI-1, "Excessive Plant Leakage Unit 2." The reactor vessel flange leakoff line was isolated as directed by procedure.
1041	Vessel flange temperature indication trended down and sump level inputs and trends appeared to level off.
1105	Operators estimated leak rate to be 36 gpm. Operators entered TS 3.4.13, Reactor Operational Leakage, Condition A (required to reduce leakage within 4 hours or be in Mode 5 in 36 hours).

1115	Operators secured excess letdown lineup as directed by procedure and closed 2RC8037A at that time. The valve indicated full closed in the control room, but there was no change in RCDT indication or leak rate when the valve closed.
1118	Operators declared a Notification of Unusual Event based on meeting Emergency Action Level (EAL) MU6, "RCS Leakage for 15 minutes or longer," due to unidentified leakage greater than 10 gpm for more than 15 minutes.
1154	Notification of Unusual Event was reported to the NRC headquarters as Event Notification (EN) 51931
1210	Operators initiated plant cooldown intending to place the unit in Mode 5.
1320	Operators closed 2RC8039A in containment. Cooldown was stopped while the operators assessed impact of closing the loop isolation valve.
1355	Operators determined that RCDT parameters were trending downward toward normal (RCDT pressure was 4 psig and temperature was 237°F and trending downward. Operators determined that leakage had been reduced to less than 10 gpm by closing the 2RC8039A.)
1459	Site determined that the conditions of EAL MU6 were no longer met and terminated the Notice of Unusual Event.
1500	The post-event walk down in containment determined that input to the RCDT was a result of primary system flow through 2CV8350, RCS Loop Drain Header to RCDT Isolation Valve, to the RCDT. When the excess letdown lineup was established, this valve became the single barrier between the primary water and the RCDT.

a. Inspection Scope

The inspectors responded to the site and monitored both the plant conditions and the operator actions taken in response to the event. The inspectors verified that the operator actions were appropriate for the plant indications and in accordance with station procedures. The licensee's staff notified the Senior Resident Inspector early in the event which allowed the inspector to notify the NRC regional management of plant conditions and respond to the plant while further event diagnosis and event classification were still in progress. After arrival on site, the senior resident inspector responded to the main control room and independently assessed plant conditions while performing control board walkdowns. After the event was terminated, the inspectors reviewed the event classification and determined that notifications were timely and met program and regulatory requirements.

The operators and engineers responding to the issue walked down different areas of containment using thermography and the leakage flowpath was verified to be through 2CV8350 as described above and subsequently verified to have been isolated by

closure of 2RC8039A. The inspectors monitored the licensee's actions to assess the equipment issues and potential damage to plant equipment as a result of the event. IRs were written for the event, the unexpected alarms, and for the failure of 2RC8037A to isolate the leak. The licensee's initial causal evaluation determined the 2CV8050 valve had "relaxed" after pressurization and heat-up allowing flow to the RCDT. After the RCDT pressurized, the tank relief valve lifted discharging water into the containment floor drain sump and resulting in the unidentified leakage indication.

The integrity of the closed 2CV8350 valve was verified when the RCS loop drain header was later pressurized using the 2RC8039C and 2RC8037C valves with no leakage indicated to the RCDT. Administrative controls were established by the licensee to control valve manipulation of the affected valves until the causal investigation and corrective actions were completed.

The licensee could not determine what the maximum RCDT temperature was during the event and promptly performed a review of all equipment in the area that could have been impacted. Isolation valves in three containment penetrations with piping connected to the RCDT were determined to have been potentially degraded by high temperature conditions in the RCDT. The licensee promptly determined that those valves were inoperable and isolated these penetrations in accordance with TS 3.4.14, "Primary Containment Isolation Valves," pending further analysis or repair. Additional IRs were written to track the extent of condition investigation.

The vessel flange leak off alarm was determined to have resulted from the high temperature primary water entering the shared inlet line to the RCDT causing the thermocouple in the flange leak off line to measure a temperature increase. The inspectors concluded that no reactor pressure flange seal leakage actually occurred during the event.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

No findings were identified.

.2 (Closed) Licensee Event Reports 05000454/2012–001, Revision 00 and Revision 01, "Unit 2 Loss of Normal Offsite Power and Reactor Trip and Unit 1 Loss of Normal Offsite Power Due to Failure of System Auxiliary Transformer Inverted Insulators"

In 2012, the licensee reported two events that had similar causes, each involving the loss of offsite power. The first occurred on January 30, 2012, on Unit 2 and the second occurred on February 28, 2012, on Unit 1. In both cases, a porcelain insulator failed in the switchyard resulting in a loss of offsite power to the associated Unit. The Unit 1 failure did not result in a trip of the Unit, but the Unit 2 failure did result in a plant trip. Each failure resulted in the declaration of a Notification of Unusual Event.

The LER and the associated event was first discussed in IR 05000454(455)/2012002. The LER was not closed at that time pending the inspector's review of the licensee's root cause evaluation and corrective action plan. In addition, an NRC Special Inspection Team was dispatched following the Unit 2 event and the results of the inspection were documented in IR 05000455/2012008. That inspection documented an Unresolved Item (URI 05000454/2012008–01) pending the results of an internal Task Interface

Agreement (TIA) with the Office of Nuclear Reactor Regulation (NRR). The root cause of the events was identified to be a manufacturing defect in switchyard insulators. The insulators were manufactured by Ohio Brass and the defect was characterized as poorly vitrified porcelain that contained a high density of porosity and micro-cracks.

The January 30, 2012, event was further complicated by the undervoltage protection scheme in place at the time. The insulator failure initially resulted in an open phase condition on the "C" phase of the safety-related 4.16 KVAC [Kilo-Volts Alternating Current] supply that was not detected by the bus undervoltage protection relays and, as a result, the buses did not automatically switch over to the emergency diesel generators. Operator diagnosis and action was required to disconnect from the degraded offsite supply.

The station promptly replaced all of the Ohio Brass insulators associated with both Unit's system auxiliary transformers (SATs) and main transformers (MPTs) with insulators from a different manufacturer. The licensee also developed, installed, tested, and activated a new undervoltage relay protection circuit for the offsite Class 1E lines to provide protection for significant grid or switchyard events such as the ones reported in these LERs. The licensee ultimately replaced over 540 Ohio Brass insulators and completed elimination of the Ohio Brass insulators from the switchyard during the Unit 2 refueling outage that ended on May 15, 2016.

Final resolution of questions raised during the Special Inspection concerning the original undervoltage protection design, and regulatory questions regarding design requirements are tracked by the open URI discussed above. These two LERs are closed.

This event follow-up review constituted one sample as defined in IP 71153–05.

.3 (Closed) LER 05000454/2016–001–00: Auxiliary Feedwater Diesel Intake Design Deficiency Related to Turbine Building High Energy Line Break Resulted in an Unanalyzed Condition Due to Insufficient Validation of Vendor Analysis Inputs

On March 7, 2016, the licensee performed an evaluation at Byron Generating Station for a design configuration issue with the auxiliary feedwater pump diesel engine suction from the turbine building after concerns were raised by the NRC at another Exelon station. The licensee determined that the existing configuration did not adequately support diesel engine operation with high energy line break (HELB) conditions in the turbine building. The licensee entered this issue into their CAP and entered TS LCO 3.7.5, "Auxiliary Feedwater (SF) System," Condition A, "One AF train inoperable," for Unit 1 and Unit 2 for the "B" of each unit inoperable. The licensee implemented a temporary configuration change (i.e., temporary modification) to change the engine combustion air supply to the auxiliary building (where it is not susceptible to a HELB) instead of from the turbine building.

The inspectors reviewed the temporary configuration change package, installation, and post-modification testing and documented the completed inspection sample for the modification in Section 1R18 of this report. The AF trains were declared operable on March 8, following the installation of the modification and completion of the post-modification testing of the AF diesel-driven pumps. Additionally, compensatory actions were implemented to monitor for a potential radioactive material release from the engine exhaust to the atmosphere and to institute a compensatory fire watch due to the

configuration change disabling the carbine dioxide fire suppression system and opening the doors to the diesel pump room.

The cause of the event was insufficient validation of vendor analysis inputs in 1993 when an engineering product was performed to review the AF diesel engine's ability to function during a turbine building HELB. The engineering product used the diesel engine manufacturer's evaluation without performing an independent review to verify the vendor's conclusion. Additional planned corrective actions included development and installation of a permanent modification to re-route the AF air intake. The enforcement aspects of this issue are discussed in Section 4OA7. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153–05.

4OA5 Other Activities

.1 (Closed) Notice of Violation 05000454/2015008–09; 05000455/2015008–09: Failure to Promptly Correct an NRC-Identified NCV Associated with the Capability to Detect and Isolate ECCS Leakage

The inspectors reviewed the licensee's letter of reply to the notice of violation (VIO) dated August 20, 2015. The letter included: (1) the reason for the violation; (2) the corrective steps taken and the results achieved; (3) the corrective steps that would be taken; and (4) the date that full compliance would be achieved. The inspectors reviewed the corrective action documentation and supporting reference information and determined whether the causal evaluation was conducted to the appropriate level of detail and corrective actions were prioritized commensurate with the safety significance of the issues. The inspectors also reviewed engineering change documents produced to support a UFSAR change, which clarified the event scenario and leak detection availability. The licensee documented in their CAP that full compliance was achieved on September 10, 2015, when the UFSAR was updated with applicable reference documents and verbiage to reflect the plant's leak detection capabilities. This violation is closed.

.2 (Closed) VIO 05000454/2015007–03; 05000455/2015007–03: Failure to Analyze RHUT [Recycle Holdup Tank] Inlet Piping Loads

The inspectors reviewed the licensee's letter of reply to the VIO dated October 19, 2015. The letter included: (1) the reason for the violation; (2) the corrective steps taken and the results achieved; (3) the corrective steps that would be taken; and (4) the date that full compliance would be achieved. The licensee entered the original issue into the CAP as IR 1285566. This violation was entered as IR 2559727. The inspectors reviewed the corrective action documentation and supporting reference information and determined whether the causal evaluation was conducted to the appropriate level of detail and corrective actions appeared to be prioritized commensurate with the safety significance of the issues. The cause of the failure to implement timely actions was identified to be inadequate oversight and prioritization of site projects to drive the issue to resolution. Contributing causes were identified as extensive engineering resource and time to resolve issues with legacy piping analysis and flow models to support required modifications. The inspectors also reviewed the plant modifications and engineering change documents produced to correct the original condition. The licensee documented in their CAP that full compliance was achieved on October 14, 2015, when the

installation of modifications required to support the evaluations of dynamic loading was completed. This violation is closed.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 12, 2016, the inspectors presented the inspection results to Mr. M. Kanavos, Site Vice President, 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.

.2 Interim Exit Meetings

Interim exit was conducted for:

- The inspection results for the areas of radiological hazard assessment and exposure controls; occupational ALARA planning and controls; in-plant airborne radioactivity control and mitigation; and occupational dose assessment with Mr. B. Barton, Radiation Protection Manager, on April 29, 2016.

- The results of the inservice inspection with Mr. M. Kanavos, Site Vice President, and other members of the licensee staff on May 4, 2016.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

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 the NRC Enforcement Policy for being dispositioned as NCVs.

- Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, that the licensee provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program. Contrary to the above, the licensee identified that they failed since original plant construction to verify the adequacy of the diesel driven AFW pump design. Specifically as discussed in the review of LER 05000454/2016–001–00 in Section 4OA3 of this report, the licensee failed to verify the diesel driven AFW pump could perform its safe shutdown function following a HELB in the turbine building. Since the diesel’s air intake was located in the Turbine Building, it would be impacted by a HELB. The licensee entered this issue into their CAP and took immediate corrective actions by declaring both the Unit 1 and Unit 2 diesel driven AFW pumps inoperable and then restored operability of the pumps by implementing temporary plant modifications to relocate the diesel air intakes to the auxiliary building where the environment was not susceptible to a HELB. The licensee’s planned corrective actions include a permanent plant modification to relocate the air intake to a location that was not susceptible to a HELB.

The performance deficiency was determined to be more than minor because it was associated with the Mitigating Systems cornerstone attribute of Design Control and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to verify that the diesel driven AFW pump could perform its safe function following a HELB event in the turbine building did not ensure its availability, reliability, and capability to respond to the initiating event. Since the finding did represent an actual loss of function of at least a single Train for greater than its Technical Specification Allowed Outage Time, a Detailed Risk Evaluation was performed which concluded that the estimated change in core damage frequency was approximately 3.4E–7/year, which represented a finding of very low safety significance (Green).

- Technical Specification 5.4.1.c requires that written procedures shall be established, implemented, and maintained covering the Fire Protection Program implementation. Step 4.2.9 of OP–MW–201–007, "Fire Protection System Impairment and Control," stated, "Compensatory measures for inoperable fire protection SSCs shall be established in accordance with site specific TRM (or equivalent document) and impairment procedures. TRM LCO 3.10.g requires implementation of an hourly fire watch or establishment of alternate compensatory measures. Contrary to the above, an hourly fire watch was not established for the lower cable spreading room on March 11, 2016, when the fire suppression system was removed from service and the requirements of the alternate compensatory measure were no longer satisfied. Specifically, the alternate compensatory measure required the suppression and detection systems to be available and when the requirements were no longer satisfied, the hourly fire watch should have been re-established. The condition existed for approximately 5 hours and fire detection remained operable during the entire period. The licensee entered this issue into their CAP as IR 2639686.

  The performance deficiency was determined to be more than minor because it adversely impacted the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences due to external events such as fire. Specifically, the failure to implement the analyzed compensatory measures reduced the reliability of the systems required for safe shutdown. The inspectors screened the finding using IMC 0609, "Significance Determination Process," Attachment 04, "Initial Characterization of Findings," Appendix A, "The Significance Determination Process (SDP) for Findings at Power," Exhibit 2, "Mitigating Systems Screening Questions." The Part B and D.1 questions were answered "No", but question D.2 was answered "Yes". Since the detection system remained operable during the entire period, one of the D.2.a conditions was satisfied and the condition represented a finding of very low safety significance (Green). The issue was also reviewed using IMC 0609 Appendix F resulting in a delta CDF of 4.4E–7/year which also screened as having very low safety significance (Green).

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

M. Kanavos, Site Vice President
D. Spitzer, Regulatory Assurance Manger
S. Kerr, Organizational Effectiveness Manager
G. Contrady, NRC Coordinator
J. Armstrong, Security Manager
T. Faley, Maintenance Manager
K. Retzke, Operational Analysis Department Manager
E. Hernandez, Operation Director
P. Boyle, Work Management Director
H. Welt, Engineering Senior Manager
D. Anthony, Corporate NDE Manager
R. McBride, ISI Program Engineer
K. McGuire, Chemistry Manager
J. Feimster, Projects (Peening Engineering Lead)
M. Swartz, Senior NDE Specialist
C. Mckean, NDE Services
P. Thimmesch, Engineering Programs Manager
B. Barton, Radiation Protection Manager

U.S. Nuclear Regulatory Commission

E. Duncan, Branch 3 Chief, Division of Reactor Projects
J. McGhee, Byron Senior Resident Inspector
J. Draper, Byron Resident Inspector

Illinois Emergency Management Agency (IEMA)

C. Thompson, Resident Inspector, IEMA
B. Metro, IEMA
L. Torres, IEMA

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000454/2016002–01 05000455/2016002–01	FIN	Failure to Perform ASME Code Case Required Extent of Condition to Identify Unacceptable Piping Flaws
05000454/2016002–02 05000455/2016002–02	NCV	Failure to Comply With Radiation Work Permit Requirements Resulting In An Unplanned Dose Rate Alarm

Closed

05000454/2016002–01 05000455/2016002–01	FIN	Failure to Perform ASME Code Case Required Extent of Condition to Identify Unacceptable Piping Flaws
05000454/2016002–02 05000455/2016002–02	NCV	Failure to Comply With Radiation Work Permit Requirements Resulting In An Unplanned Dose Rate Alarm
05000454/2015008–09 05000455/2015008–09	VIO	Failure to Promptly Correct an NRC-Identified NCV Associated with the Capability to Detect and Isolate ECCS Leakage
05000454/2015007–03 05000455/2015007–03	VIO	Failure to Analyze RHUT Inlet Piping Loads
05000454/2012–001–00 05000455/2012–001–00	LER	Unit 2 Loss of Normal Offsite Power and Reactor Trip and Unit 1 Loss of Normal Offsite Power Due to Failure of System Auxiliary Transformer Inverted Insulators
05000454/2012–001–01 05000455/2012–001–01	LER	Unit 2 Loss of Normal Offsite Power and Reactor Trip and Unit 1 Loss of Normal Offsite Power Due to Failure of System Auxiliary Transformer Inverted Insulators
05000454/2016–001–00	LER	Auxiliary Feedwater Diesel Intake Design Deficiency Related to Turbine Building High Energy Line Break Resulted in an Unanalyzed Condition Due to Insufficient Validation of Vendor Analysis Inputs

Discussed

05000454/2012008–01	URI	Inadequate Undervoltage Protection

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather Protection

- IR 02459911; Louvers Broken Downstream of 2VE01C
- EC 402280; Evaluation of FME in Unit 1 VP Chilled Water System
- 2016 Plant System Readiness Reviews for VE and WO
- IR 02443853; Abnormal Conditions on 1B VP Chiller
- IR 02472845; 1A VP Chiller Tripped on High Compressor Motor High Temp
- IR 02493653; 1B Chilled Water Pump As-Found Conditions
- Letter from M. Kanavos to D. Enright; Subject: Certification of 2016 Summer Readiness; May 15, 2016
- WC–AA–107, Revision 16; Seasonal Readiness

1R04 Equipment Alignment

- BOP CV–M2A, Revision 7; Chemical and Volume Control System Train “A” Valve Lineup
- BOP CV–E2A, Revision 3; Chemical & Volume Control Train “A” Electrical Lineup
- M–138, Sheet 4, Revision BI; Diagram of Chemical & Volume Control and Boron Thermal Regeneration
- M–138, Sheet 3A, Revision AW; Diagram of Chemical and Volume Control and Boron Thermal Regeneration
- BOP CV–M1, Revision 34; Unit One Chemical and Volume Control System Valve Lineup
- BOP CV–M1B, Revision 11; Unit One Chemical and Volume Control System Train “B” Valve Lineup
- M–136, Sheet 1, Revision BB; Diagram of Safety Injection
- M–136, Sheet 2, Revision AD; Diagram of Safety Injection
- M–135, Sheet 1B, Revision BD; Diagram of Reactor Coolant Loop 1
- M–135, Sheet 2, Revision AP; Diagram of Reactor Coolant Loop – 2
- M–135, Sheet 3, Revision AW; Diagram of Reactor Coolant Loop – 3
- M–135, Sheet 4, Revision AT; Diagram of Reactor Coolant Loop – 4
- B2R19 Shutdown Safety Management Plan (SSMP); April 1, 2016
- BOP SI–M1, Revision 018; SI System Valve Lineup
- BOP SI–M2A, Revision 003;Train “A” SI System Valve Lineup
- BOP SI–M2B, Revision 004;Train “B” SI System Valve Lineup
- BOP SI–M2C, Revision 011; SI System Valve Lineup
- BOP SI–E2, Revision 008; SI System Electrical Lineup
- BOP SI–E2A, Revision 004; SI Train “A” System Electrical Lineup
- BOP SI–E2B, Revision 002; SI Train “B” System Electrical Lineup
- BOP SI–E2C, Revision 005; SI System Electrical Lineup
- M–39, Sheet 1, Revision BA; Diagram of Condensate (Make-up & Overflow)
- M–37, Revision BE; Diagram of Auxiliary Feedwater
- M–42, Sheet 3, Revision BD; Diagram of Essential Service Water

1R05 Fire Protection

- Pre-Fire Plan, Revision 2, FZ 5.2–2; Auxiliary Building 426’ 0” Elevation; Division 21 ESF Switchgear Room;
- Pre-Fire Plan, Revision 1, FZ 5.1–2; Auxiliary Building 426’ 0” Elevation; Division 22 ESF Switchgear Room;
- Pre-Fire Plan #152, Revision 2, FZ 11.5A–1; Auxiliary Building 414’ 0” Elevation; Unit 1 Electrical Penetration Area;
- Pre-Fire Plan #157, Revision 2, FZ 11.6–1; Auxiliary Building 414’ 0” Elevation; Division 12 Electrical Penetration Area
- Pre-Fire Plan #131, Revision 1, FZ 11.3G–2; Auxiliary Building 364’ 0” Elevation; 2B Centrifugal Charging Pump Room
- Pre-Fire Plan #116, Revision 3, FZ 11.3–2; Auxiliary Building 364’ 0” Elevation; Unit 2 Containment Pipe Penetration Area
- Pre-Fire Plan #129, Revision12, FZ 11.3F–2; Auxiliary Building 364’ 0” Elevation; 2B Safety Injection Pump Room
- IR 02666315, NRC ID: Barrel of Used Oil Stored Outside AF Pump Rooms

1R08 Inservice Inspection Activities

- IR 02662411; ASME Code Case N–586–1 Determination of Root Cause; dated April 28, 2016
- IR 02661963; Unacceptable Linear Indication Found during ISI Examination; dated April 27, 2016.
- IR 2660692 RPV Head Penetrations Wetted Before As-Found VT Completed; dated April 25, 2016
- IR 02659196; Code Non-Conformance did not Get NRC Approval; dated April 21, 2016
- IR 02658617; NRC Questioning of WPS 8–8–GTSM Qualification; dated April 20, 2016
- IR 02662411; ASME Code Case N–586–1 Determination of Root Cause; dated April 28, 2016
- IR 02516949; 2PS9354A – Pressurizer Air Operated Valve; dated June 19, 2015
- IR 02522775; 2FC02F – Unit 2 Spent Fuel Pit Filter; dated July 1, 2015
- IR 02517344; 2CV190 – Injection Isolation Valve; dated June 20, 2015
- IR 02443497 Additional Repairs Required on DC JW Cooler; dated January 28, 2015
- IR 02431695 SX Piping Leak: 0SX02D–30” U–0 CC HX SX Outlet Piping; dated January 1, 2015
- IR 02408385; Low UT-T Reading OSX01AA–48; dated November 3, 2014
- IR 02396331 Low Wall Thickness Reading on SX – Scope Expansion for B2R19; dated October 16, 2014
- IR 02394500; B2R18 ISI Examination Coverage Less than 90%; dated October 12, 2014
- IR 02393568 Foreign Objects Found in a 2A SG Secondary Side B2R18; dated October 10, 2014
- IR 02393581 Foreign Objects Found in 2C SG Secondary Side B2R18; dated October 10, 2014
- IR 02393594 Foreign Objects Found in 2D SG Secondary Side B2R18; dated October 10, 2014
- IR 02390926; 2SXA9A–6” UT Identified Areas Below Min. Wall Requirements; dated October 4, 2014
- IR 02391224; U2 Containment Moisture Barrier Degraded; dated October 4, 2014
- IR 02389459; ISI Surface Indication 2MS01AH–30.25 Welded Attachment E–2; dated October 1, 2014.
- IR 02387497; 2RC8037C – 2C RC Loop Drain Valve Leak; dated September 29, 2014

- IR 01622269; Weld Size to Install Branch Fittings on ASME Lines/Vessels; dated February 17, 2014
- IREVA 54–ISI–603–008; Automated Ultrasonic Examination of RPV Closure Head Penetrations Containing Thermal Sleeves; dated August 20, 2015
- AREVA 54–ISI–604–013; Automated Ultrasonic Examination of Open Tube RPV Closure Head Penetrations; dated August 25, 2015
- AEVA 51–9199–524–000; Technical Justification for Demonstrating the Capabilities of CRDM/CEDM Examination Procedures to Nozzle Bores with Thermal Sleeve Centering Tab Wear; Revision 0
- ASME Weld Data Record; WO 01634753–01, Fitting Elbow 4 inch Schedule 80; dated September 5, 2014
- Certification of Qualification (MT, PT, UT and VT); M. Parker; dated January 7, 2016
- Certification of Qualification (MT, PT, UT and VT); C. Congdon; dated February 2, 2016
- Certification of Qualification (MT, PT, UT and VT); K. Fish; dated January 6, 2016
- EC 0000399643; Main Steam Line 2MS01AA Snubber Attachment lug weld indication B2R18 Evaluation Per ASME Section XI In-service Inspection Program; Revision 0
- EC 0000398736; Pre-Mode 4 Final Condition Monitoring and Operational Assessment
- 6E–14–105, Rev 0 B2R18 Evaluation of Foreign Objects Not Retrieved From the Unit 2 Steam Generators; Revision 0
- EC 0000398735; B2R18 SG Degradation Assessment; Revision 0
- EC 0000404386; B2R19 SG Degradation and Operational Assessment; Revision 0
- ER–AP–335–001; Bare Metal Visual Examination for Nickel Alloy Materials; Revision 4
- ER–AA–335–001; Qualification and Certification of Nondestructive Examination (NDE) Personnel; Revision 7
- ER–AP–331–1001; Boric Acid Corrosion Control (BACC) Inspection Locations, Implementation and Inspection Guidelines; Revision 9
- ER–AP–331–1002; Boric Acid Corrosion Control Program Identification Screening and Evaluation; Revision 9
- ER–AP–331; Boric Acid Corrosion Control (BACC) Program; Revision 7
- ER–AP–335–001; Bare Metal Visual Examination for Alloy 600/82/182 Materials; Revision 4
- ER–AA–335–002; Liquid Penetrant Examination; Revision 9
- ER–AA–335–003; Magnetic Particle Examination; Revision 7
- EXE–PDI–UT–2; Ultrasonic Examination of Austenitic Piping Welds in Accordance with PDI–UT–2; Revision 7
- EXE–PDI–UT–1; Ultrasonic Examination of Ferritic Piping Welds in Accordance with PDI–UT–1; Revision 7
- PI–AA–125; Corrective Action Program Procedure; Revision 2
- PI–AA–125–1001; Root Cause Analysis Manual; Revision 2
- PQR A–001; dated October 19, 1998
- PQR A–002; dated March 9, 1999
- PQR 1–50C; dated January 3, 1984
- PQR 1–51A; Procedure Qualification Record; December 28, 1983
- PQR 4–51A; Procedure Qualification Record; September 12, 1986
- PQR A–003; Procedure Qualification Record; February 8, 2000
- PQR A–004; Procedure Qualification Record; February 8, 2000
- Report B2R12–MT–001; 2MS07AD–28 E–2; dated September 28, 2005
- Report B2R19–UT–033; 2SI06BB–24/C28 – Pipe-to-Elbow; dated April 25, 2016
- Report B2R19–UT–045; 2RH01BA–12/C21 – Pipe-to-Elbow; dated April 27, 2016
- Report B2R19–UT–030; 2CS06AA–6/C12 – Pipe-to-Elbow; dated April 24, 2016
- Report B2R19–MT–002; 2MS07AD–28/E–2 – Welded Stanchion; dated April 27, 2016

- Report 16–MT–022; 2MS07AD–28/E–2 - Welded Stanchion; dated April 29, 2016
- Report B2R19–UT–008; 2FW87CC–6/C32 – Pipe-to-Elbow; dated April 21, 2016
- Report B2R19–UT–007; 2FW87CC–6/C33 – Elbow-to-Pipe; dated April 21, 2016
- Report 2014–276; Radiographic Examination and Interpretation Report – Weld 19 and 20, WO 01634753–01; dated August 7, 2014
- Report; VT–2 Visual NDE Report 2AF03EA, 2AF03ED, 2AF049A, 2AF049D; dated October 23, 2014
- SG–SGMMP–14–03; Byron Unit 2 B2R18 Steam Generator Condition Monitoring and Operational Assessment; Revision 0
- WO 01634753–01; AF Connections for Flex Unit 2 EC 393364
- Drawing M–122, Revision BD
- WPS 8–8–GTSM; ASME Welding Procedure Specification Record; Revision 3
- WPS 1–1–GTSM–PWHT; ASME Welding Procedure Specification Record; Revision 3

1R11 Licensed Operator Requalification Program

- 2BGP 100–5, Revision 63; Plant Shutdown and Cooldown
- 2BGP 100–ST1, Revision 30; Plant Shutdown and Cooldown Flowchart, 2BGP 100–5 Flowchart
- 2BGP 100–4T3, Revision 19; Load Change Instruction Sheet for Power Reduction ,15% in One Hour

1R12 Maintenance Effectiveness

- IR 02344871; Insulator Fragment Found on Ground Near SAT [System Auxiliary Transformer] 242–2
- IR 02441512; December Unit 1 Load Drop for Insulator , Planned or Unplanned
- IR 02487767; Chipped Insulator
- IR 02654288; Ohio Brass Insulator Maintenance Rule Evaluation
- IR 02430376; Bus 6 Support Insulator – Ohio Brass – Top Petticoat 2nd Stack
- IR 02641898; 345 KV Bus 10 Ohio Brass Support Insulator Failure
- Maintenance Rule Function SY–01 and SY–02 Evaluation Summaries for the Period 06/01/2014 to 06/15/2016
- IR 02681365; BT [Bus Tie] 12–13 Air System Pressure Alarm Did Not Reset
- WO 01920061; 0FPJ7A–4” UT Detected 2 Areas Below the Minimum Criteria
- OP–AA–108–115, Revision 13; Operability Determinations (CM–1)
- EC 404949, Revision 0; Functionality Eval for Through Wall Leak on 0FPE3A–6” per N–513–3
- Maintenance Rule System Basis Document for Fire Protection Function FP–10; Maintain System Integrity to Preclude Flooding Hazard to Other Critical Equipment
- ECR 423439; FP wall Thickness Calculations to Support NDE UT Inspections
- UT Thickness Examination Report 16–UT–061; April 27, 2016
- UT Thickness Examination Report 16–UT–059; April 27, 2016
- IR 01636806; Pinhole Leak on FP Line in AB
- ECR 423225; 0FPK1A–4” EOC Min Wall Thickness Locations
- IR 02661892; 0FPJ7A–4” UT Detected 2 Areas Below the Minimum Criteria
- IR 02661900; 0FPJ8A–4” UT Detected 2 Areas Below the Minimum Criteria
- IR 02662478; N–513 Continued EOC for FP – Location 1
- IR 02662479; N–513 Continued EOC for FP – Location 2
- IR 02662480; N–513 Continued EOC for FP – Locations 3, 4, and 5
- M–52, Sheet 1, Revision AI; Diagram of Fire Protection (Category I)
- M–52, Sheet 7, Revision Z; Diagram of Fire Protection Auxiliary Building

- IR 02669765; Thru Wall Leak on Fire Protection Header
- IR 02639930; Missed EOC on AB FP Line
- IR 02652145; NRC ID: FP Leak in 2014 Did Not Receive Code Case N–513 Eval
- IR 02644395; Location 1 EOC for IR 01636806 FP Historic Leak
- IR 02644401; Location 2 EOC for IR 01636806 FP Historic Leak
- IR 02644413; Location 3 EOC for IR 01636806 FP Historic Leak
- IR 02644415; Location 4 EOC for IR 01636806 FP Historic Leak
- IR 02688352; NRC ID MRule FP CME

1R13 Maintenance Risk Assessments and Emergent Work Control

- OU–AP–104, Revision 21; Shutdown Safety Management Program Byron/Braidwood Annex
- ER–AA–600–1043, Revision 6; Shutdown Risk Management
- OU–AA–103, Revision 15; Shutdown Safety Management Program
- IR 2654848; Need Additional Spare Containment Penetration Covers Ordered
- B2R19 Shutdown Safety Management Plan (SSMP); April 1, 2016
- IR 02660908; 1B CV Pump Outboard Motor Bearing Bad Oil
- IR 02661452; Ops Focus: 4.0 Critique for 1B CV Pump Oil Discoloration
- BY–MODE–013; Revision 1; TS 3.0.4.b Evaluation – Entry to Modes 2 and 1 with 2PR11J, 2RC014B, 2RC014D, Containment Isolation Valves, and Sub-cooling Margin Monitor Inoperable.

1R15 Operability Determinations and Functional Assessments

- IR 02660436; 2SX07HA–20” NDE UT Thickness Below Min Wall Requirements
- ECR 422807, dated March 14, 2016; Acceptance Criteria For Min Wall For Raw Water Program
- ECR 423378, dated April 25, 2016; Min Wall Thickness for 2SX07HA–20”
- IR 02663826; Min Wall Thickness <87.5% of Nominal Wall for SX Piping
- IR 02662093; 1B AF Pump Adverse Oil Temperature Trend During Extended Run
- WO 01871156; 1B AF Pump Oil Cooler Piping Replacement Recommendation
- IR 02648029; 1AF01AB Failed GL 89–13 Acceptance Criteria
- EC 382473.Revision 0; 1B AF Pimp Lube Oil Cooler Piping Wrong
- EC 353392, Revision 1; Evaluation of Availability of 1AF01PA while 1SX101A was Potentially Isolated from 3/15/04 to 6/29/04
- IR 02652519; Unit 1 Containment ECCS Gas Void UT Exam Results – 1SI094
- IR 02672946; Spurious Bus 212 Inverter Trouble Alarm
- IR 02673423; Bus 212 Inverter Trouble Alarm 2nd Day in a Row
- IR 02676660; Relay (X20) Wiring Configuration Not Match for Inverter 212 CCP
- M–61, Sheet 4, Revision AZ; Diagram of Safety Injection
- EC 394562; Operability Evaluation 13–006, Gas Voids in RH to CL [Cold Leg] Injection Path. Upstream of 2SI8818A and 2SI8818B
- Westinghouse Letter LTR–LIS–08–543, PWROG Position Paper on Non-condensable Gas Voids in ECCS Piping: Qualitative Engineering Judgement of Potential Effects on Reactor Coolant System Transients Including Chapter 15 Events
- IR 02673848; Tornado Protection Design Nonconforming Condition
- Operations Standing Order 16–020, dated 5/25/2016; Enforcement Guidance Memorandum for Tornado-Generated Missile Protection Noncompliance
- 0BOA ENV–1, Revision 118; Adverse Weather Conditions, Unit 0
- Shift Manager Turnover –Days to Nights 5/26/2016
- Regulatory Issue Summary (RIS) 2015-06, dated June 10, 2016; Tornado Missile Protection

- Enforcement Guidance Memorandum (EGM) 2015–002, dated June 10, 2016; Enforcement Discretion for Tornado-Generated Missile Protection Noncompliance
- IR 02678870; One Tornado EGM Initial Comp Measure Not Credible

1R18 Plant Modifications

- IR 02636112; Question on AFW Diesel Air Intake
- IR 02637248; Monitoring AF Diesel Release Path Improvements
- EC 404997, Revision 000; Remove AF Diesel Air Intake Elbow and Blank Off TB Air Intake
- WO 01904882; Install TCCP 404997 on U1 AF Diesel Air Intake
- WO 01904883; Install TCCP 404997 on U2 AF Diesel Air Intake
- TCCP 404997, Revision 0; 50.59 Screening (6E–16–027) and 50.59 Evaluation (6G–16–001)
- IR 02667058; Follow-up Exam for Rx Head Peening Leakage
- IR 2667990; ID Peening Not Completed on 5 U2 RV Head Penetrations; dated May 11, 2016.
- IR 02664984; Incorrect Tool Parameters Entered for OD Tool; dated May 4, 2016
- IR 02664417; OD Wrist Errors Causing Incorrect Peening Coverage; dated May 3, 2016
- IR 02664415; U2 Rx Head at P–73 Funnel Disengaged from Thermal Sleeve; dated May 3, 2016
- IR 02663986; B2R19 Critical Path Delay- Rx Head Peening Equipment Issues; dated May 2, 2016
- IR 02660298; B2R19LL CETC Nozzle Overflowed During CRDM Exam; dated April 24, 2016
- AREVA 150–8086004–000; SPQR Qualification of Cavitation Peening Process for Reactor Closure Head Nozzles; Revision 001
- AREVA 51–9251566–000; Evaluation of the Effect of Cavitation Peening on Ultrasonic Examination of Reactor Head Penetration Nozzles; Revision 001.
- AREVA 03–8087907; OI RVCH Nozzle Cavitation Peening System, Byron Unit 2; Revision 001.
- EC 400682, “Unit 2 Reactor Vessel Closure Head Penetration Ultra High Pressure Cavitation Peening, Revision 0.
- EPRI 3002002952; Materials Reliability Program Study of New Mitigation Technique Effects on Nondestructive Evaluation Inspectability; dated November 2014.
- MRP 3002000656; Effects of Surface Peening on the Inspectability of Nondestructive Evaluation; dated November 2013.
- IR 02655156; NRC Identified TCP Needed Auxiliary Building 383 Unit 1 Side
- IR 02652415; NRC CDBI Question – Impact on “B” AF Pumps with 383’ Fire
- WO 01806140; Unit 2 Head CRDM Nozzle Water Cavitation Peening EC 400682
- 2BOSR 1.4.3–1A, Revision 006; Unit Two Automated Rod Drop Timing Test
- 50.59 Screening No 6E–16–152, Revision 0; Installation of Temporary Power to Spent Fuel Pit Pump 2FC01P and Cubicle Coolers 2VA07CA and 2VA07CB Beyond the MR90 Maintenance Activity It Supports
- MA–BY–726–001, Revision 8; Temp Power to the FC Pump and Cubicle Coolers
- 50.59 Screening No 6E–02–0027, Revision 0; Alternate Power Source to the FC Pump and Cubicle Coolers
- WO 00602804; Install Equipment for Temp Feed to 2FC01P per MA–BY–726–001
- EC 334498, Revision 0; Alternate Power Source to the FC Pump and Cubicle Coolers
- MA–BY–726–001, Revision 0; Alternate Power Source to the FC Pump and Cubicle Coolers
- CC–AA–112, Revision 23; Temporary Configuration Changes
- CC–AA–112, Revision 4; Temporary Configuration Changes
- CC–AA–102, Revision 1; Design Impact Screening
- BOP FC–1, Revision 22; Fuel Pool Cooling System Startup and SFP Purification System Operation

1R19 Post-Maintenance Testing

- IR 02656518; 2AF004A Failed to Close When Required
- IR 02657538; 2AF004A Failed to Stay Closed to Support 2BOSR 3.2.9–1
- WO 01917002; 2AF004A Failed to Close When Required
- IR 02657667; B2R19 M3 2AF004A Stroked Too Fast
- IR 02657531; 2BOSR 3.2.9–1 Completed with Portion Untested
- IR 02660908; 1B CV Pump Outboard Motor Bearing Bad Oil
- IR 02662142; Measurements Needed During Current 2A CV Motor Work
- IR 02659557; 2CC9486 Has Excessive Leakage During LLRT (P–25)
- WO 01798630; LLRT for P–25 – 2CC9486 and 2CC9413A
- WO 01918579; 2CC9486 Has Excessive Leakage During LLRT (P–25)
- 2BOSR 6.1.1–12, Revision 8; Unit Two Primary Containment Type C Local Leakage Rate Tests and IST Tests of Component Cooling System
- M–139, Sheet 1, Revision AS; Diagram of Component Cooling
- BVP 800–39, Revision 13; Byron Containment Leakage Rate Testing Program
- WO 01920388; EOC [Extent of Condition] of 1B CV Pump Motor Coupling Issue (2B CV)
- 2BOSR 5.5.8CV.5–2a, Revision 7; Unit Two Group A Inservice Testing (IST) Requirements For 2B Charging Pump 2CV01PB
- 2BOSR 1.4.3–1a, Revision 6; Unit Two Automated Rod Drop Timing Test
- WO 01639063; Perform Automated Rod Drop Timing Test
- WO 01785576; Perform Automated Rod Drop Timing Test
- WO 01888710; AOV 1SD005D Showing Mid-Position
- WR 00516696; 1SD005D Showing Dual
- IR 02606044; 1SD005D Showing Dual Indication
- 1BOSR 6.3.5–13, Revision 9; Unit One Steam Generator Blowdown Containment Isolation Valve Stroke Test
- IR 02660740; 1SD005B Has Failed Closed
- IR 02680622; 1D MSIV [main steam isolation valve] AOP [accumulator oil pump] Unable to Control Accumulator Pressure
- WO 01931110; 1D MSIV Air/Oil Pump Cycling Excessively
- IR 02684270; 2PA20JA Primary Power Supply Failure
- WO 02684270; 2PA20JA Primary Power Supply Failure

1R20 Outage Activities

- IR 02662211; NRC ID: Graffiti Inside Containment
- Owner's Group Report – PWROG–16003–P, Revision 0–A; Evaluation of Potential Thermal Sleeve Flange Wear
- Westinghouse Report – WCAP16911–P, Revision 0; Reactor Vessel Head Thermal Sleeve Wear Evaluation for Westinghouse Domestic Plants; dated July 2008
- Westinghouse Technical Bulletin – TB–07–2, Revision 3; Reactor Vessel Head Adapter Thermal Sleeve Wear; December 7, 2015
- IR 02659344; Refuel Machine Gripper Stuck in Top of Fuel Assembly
- IR 02664415; U2 Rx Head at P–73 The Funnel Disengaged From The Thermal Sleeve
- IR 02668255; NRC ID'D: Containment Walkdown Items
- IR 02669555; Resolution of Issues Found on NRC Containment Walkdown
- 2BGP 100–3T1, Revision 27; Power Ascension Flowchart
- IR 02655018; ESOMS Program Error for Work Hour Rules
- IR 02662211; NRC ID: Graffiti Inside Containment
- IR 02662315; NRC ID – Surface Corrosion Spot on Pipe 2SX06CA

- IR 02662348; NRC ID – Surface Corrosion Spot on Pipe 2SX06EB
- IR 02662350; NRC ID – Surface Corrosion on Pipe 2SX06DD
- BOP AP–105T7, Revision 0; Bus 244 Appendix R Teledyne Lights
- 0BOL 10.i, Revision 9; LCOAR DC Emergency Lighting TRM LCO # 3.10.i
- 1BOA PRI–5, Revision 108; Control Room Inaccessibility Unit 1
- IR 02659198; NRC ID-Puddle in U–2 VCT Vlv Isle, Leak from 2CV8548A
- IR 02658335; NRC ID'd Shutdown Safety Color
- OU–AA–103, Attachment 2, Revision 15; Shutdown Safety Contingency Plan
- CO 00129485, Checklist 001; DC 212 – Outage Work Window
- CO 00126849, Checklist 001; 2CV8455 – Admin Closed As Required By 2BGP 100–5
- CO 00128933, Checklist 001; 2AF013D – Replace Actuator – Uses Valve Block
- CO 00132969, Checklist 001; 2AF013A – Valve Repack
- IR 02658772; NRC ID: Inactive Packing Leak (2RE002) – WR Only
- IR 02658771; NRC ID: Inactive Packing Leak (2RC001D) – WR Only
- IR 02674451; 4.0 Critique For Shutdown of Unit 2 For B2R19

1R22 Surveillance Testing

- WO 01638485; 2A Diesel Generator Sequencer Test
- 2BOSR 8.1.11–1, Revision 18; Unit Two 2A Diesel Generator Sequencer Test
- IR 02664775; 2BOSR 8.1.11–1 Follow Up IR (2A DG Seq Test)
- WO 01780872; LLRT for P–24 – 2CC9518, 2CC9438, and 2CC685
- 2BOSR 6.1.1–12, Revision 8; Unit Two Primary Containment Type C Leakage Rate Tests and IST Tests of Component Cooling System
- ER–AA–380, Revision 11; Primary Containment Leakrate Testing Program
- BVP 800–39, Revision 13; Byron Containment Leakage Rate Testing Program
- M–139, Sheet 1, Revision AS; Diagram of Component Cooling
- 2BVSR 7.1.1–1, Revision 11, Unit 2 Main Steam Safety Valves Operability Test
- 1BOSR 5.5.8.CC.5–2c, Revision 4, Unit One Comprehensive Inservice Testing (IST) Surveillance Requirements for Component Cooling Pump 1CC01PB
- 1BOSR 5.5.8.AF.5–1b, Revision 9; Unit One Group B Inservice Testing (IST) Requirements for Motor Driven Auxiliary Feedwater Pump 1AF01PA
- IR 00232315; U–1 AF Dual Train Inoperability
- WO 01907439; LR–1AF01PA Group B IST Requirements for Motor Driven AF Pump
- M–39, Sheet 1, Revision BA; Diagram of Condensate (Make-up & Overflow)
- M–37, Revision BE; Diagram of Auxiliary Feedwater
- M–42, Sheet 3, Revision BD; Diagram of Essential Service Water

1EP6 Drill Evaluation

- Byron 2016 Off-year Exercise Scenario Guide

2RS1 Radiological Hazard Assessment and Exposure Controls

- RWP BY–2–16–00505; Aux/CNMT Scaffold; Revision 0
- RWP BY–2–16–00681; Steam Generator Bowl Drain Replacement and ALARA Package; Revision 3
- RWP BY–0–16–00123; Engineering Surveillances/Tests/Inspections/Walk Downs Including HRAs
- RWP BY–2–16–00677; RX Head Peening and ALARA Package; Revision 2
- Survey Map #191; AB–364 U–2 Penetration Area 7; Revision 4, January 13, 2015

- Survey Map #015; AB–364 U–2 Penetration Area; Revision 7, January 12, 2015
- Survey Map #203; AB–383 General Area HX Walkway U–2; Revision 5, January 13, 2015
- Survey Map #244; RX2–390 U-2 A/D Steam Gen Platform; Revision 4, January 14, 2015
- Survey Map #243; RX2–390 C/B Steam Gen Platform; Revision 4, January 14, 2015
- Survey Map #278; RX2–XXX U–2 Containment Blank; Revision 4, January 14, 2015
- Survey Map #279; RX2–XXX U–2 Containment Blank; Revision 4, January 14, 2015
- RP–AA–350; Attachment 10 "Sample" Monitor Alarm Events Resulting in Greater Than or Equal to 1,000 DPM, Less than 50,000 DPM With a GM Frisker; Revision 16
- RP–AA–203–1001; Attachment 1 "Sample" Personnel Exposure Investigation; Revision 9
- RP–AA–460; Controls for High and Locked High Radiation Areas; Revision 28, January 26, 2016
- RP–AA–460–001; Controls for Very High Radiation Areas; Revision 6, February 11, 2016
- RP–AA–460–003; Additional High Radiation Exposure Control; Revision 3, January 16, 2016
- RP–AA–460–003; Access to HRAS/LHRAS/VHRAS in Response to a Potential or Actual Emergency; Revision 8, January 13, 2016
- RP–AA–376; Radiological Posting, Labeling, and Markings; Revision 8, September 5, 2014
- RP–AA–376-001; Radiological Posting, Labeling & Marking Standard; Revision 13, February 10, 2016
- RP–AA–800; Control Inventory and Leak Testing of Radioactive Sources; Revision 7, June 26, 2013
- RP–AA–800–001; Nationally Tracked Source Program; Revision 2, October 7, 2015
- AR 02655195 Report: Engineer Received an Unplanned Dose Rate Alarm in Area 7
- AR 02662056 Report: NRC ID: B2R19 LL Initial Containment Entry RP Briefs
- AR 02397029 Report: Emergent Resin Transfer
- AR 02400934 Report: More RP Housekeeping Issues from OPS Supervisor Walk Down
- AR 02412611 Report: Leak from Unknown Source
- AR 02427555 Report: New Portal Monitors Experienced Alarm Issues
- AR 02621921 Report: Dose Rate Alarm Due to Change of Conditions
- National Source Tracking System Confirmation Form, 2016 Annual Inventory Reconciliation

2RS2 Occupational ALARA Planning and Controls

- RP–AA–400; ALARA Program; Revision 13, December 9, 2015
- RP–AA–400–1004; Emergent Dose Control and Authorization; Revision 4, December 9, 2015
- RP–AA–400–1006; Outage Exposure Estimating and Tracking; Revision 5, February 12, 2016
- RP–AA–400–1007; Elevated Dose Rate Response Planning; Revision 2, April 1, 2014
- RP–AA–400–1009; Remote Monitoring System; Revision 2, December 9, 2015
- AR 02408363 Report: Emergent Dose Request to Support RHUT MOD Walk Down
- AR 02409724 Report: Emergent for Gas Void Monitoring
- AR 02549940 Report: Follow-Up Actions from Accumulated Dose Alarm
- AR 02651551 Report: ALARA Check-In Deficiency
- AR 02470496 Report: Problem Identification Red Driver for RP

2RS3 In-Plant Airborne Radioactivity Control and Mitigation

- RP–AA–301; Radiological Air Sampling Program; Revision 8, July 18, 2014
- RP–AA–302; Determination of Alpha Levels and Monitoring; Revision 7, July 18, 2014
- RP–AA–13; Respiratory Protection Program Description; Revision 0, January 10, 2007
- RP–AA–440; Respiratory Protection Program; Revision 12, March 4, 2016
- RP–AA–441; Evaluation and Selection Process for Radiological Respirator Use; Revision 6, February 12, 2016

- AR 02659231 Report: Unit 2 Containment Had Airborne Conditions during Head Lift
- AR 02409669 Report: Firehawk SCBA PCRA RP/BR–825–1003
- AR 02410604 Report: Too Many Respirator Qualifications Expire at End of Year
- AR 02423617 Report: Mask Fit Not Completed as Scheduled
- AR 02470604 Report: Possible Improper Signage in Operating Cage

2RS4 Occupational Dose Assessment

- RP–AA–220; Bioassy Program; Revision 11, December 14, 2015
- RP–AA–221; Whole Body Count Data Review; Revision 2, September 6, 2012
- RP–AA–250; External Dose Assessments from Contamination; Revision 6, January 9, 2015
- RP–AA–280; Occupational Exposure Reporting; Revision 9, October 30, 2015
- AR 02410131 Report: Emergent Dose Request for FIN to Work 2WFO4PA
- AR 02436167 Report: Area DLR Program Inconsistencies and Enhancements
- AR 02510869 Report: NOS ID: Incorrect Survey Map Displayed in RP Online
- AR 02518127 Report: WBC Failed Two Source Checks
- AR 02637888 Report: Sentinel Dosimetry Issuance over Exposure Possible

4OA1 Performance Indicator Verification

- 2BOSR 4.13.1–1, Revision 31; Reactor Coolant System Water Inventory Balance Surveillance Computer Calculation
- ER–AP–331–1003, Revision 9; RCS Leakage Monitoring and Action Plan
- IR 02539232; U2 RCS Leakrate Deviation Action Level I Exceeded
- IR 02547369; U1 RCS Leakrate Exceeds Deviation Level I and II
- IR 02497373; Action Deviation Level 3 for RCS Leakrate
- IR 02595109; U1 RCS Leak Rate Action Level One Deviation
- LER 454–2015–002–00; Byron Unit 1, Reactor Trip Resulting from a Phase to Phase Fault on the 1E Main Power Transformer
- LER 454–2015–004–00; Unanalyzed Condition Due to a Design Deficiency with Pressurizer Operated Relief Valve Circuitry That Could Prevent Valve Manual Closure to Mitigate Spurious Operation
- LER 454–2015–006–00; Byron Unit 1, Mode 3 Entered with Turbine Trip Safety Function Disabled Due to Safety Related Relay Leads Lifted
- LER 454–2015–005–00; Byron Unit 1, Liquid Penetrant Indications in Embedded Flaw Seal Weld Repair of Control Rod Drive Mechanism Penetration 31 During Refueling Outage
- LER 454–2015–003–01; Byron Unit 1, One Train of the Diesel Generator System Inoperable Longer Than Allowed by Technical Specifications Due to Loss of Diesel Fuel Oil System Volume
- LER 454–2015–001–00; Byron Unit 1, Inadequate Application of Technical Specifications Related to Main Steam Isolation Valves and Actuator Trains

4OA2 Identification and Resolution of Problems

- IR 02661939; B2R19LL Related to Clarification of BOL PC–1 Requirements
- IR 02650149; Ops Focus: 2BOSR 8.9.1–2, ESF Onsite Power Distribution Surveillance
- IR 02667024; B2R19 CB&I Performance Review Roll-up
- IR 02658770; Hose Station Blocked by Scaffold
- IR 02663054; B2R19 LL Smoke from MSR 2B Opening
- IR 02631850; Clearance & Tagging Issue CO [Clearance Order]

- IR 02648369; NOS [Nuclear Oversight] Identified: NSWP [Nuclear Station Work Procedure] Attributes N/A'd
- IR 02650921; NOS Identified: Work Planning Missed Installing Hold Point
- IR 02651543; NOS Identified: Undersized Fillet Weld
- IR 02651745; Safety Champion Observation/Behaviors
- IR 02653707; Security – Safety Champion Observation
- IR 02653814; Safety Champion Observation
- IR 02655100; Safety Champion Observation – 4/12/16
- IR 02658555; B2R19 LL Scaffold Modification Performed Out of Process
- IR 02660422; Housekeeping Walkdown April Zones 50–53 – Auxiliary Building 383
- IR 02663054; B2R19 LL Smoke From 2B MSR [Moisture Separator Reheater] Opening
- IR 02668152; Aggregate Review Requested for CD/CB [Condensate/Condensate Booster] & EH [Electrohydraulic control system] Pump Rework
- IR 02668958; 2RY8010B Inlet Flange Leak

4OA3 Follow-Up of Events and Notices of Enforcement Discretion

- IR 02669711; Unit 2 RCDT Pressurization and Unusual Event
- IR 02670744; 4.0 Critique for Unit 2 RCS Leakage
- IR 02669717; 2RE9152B Leaking Steam/Blown Diaphragm
- IR 02669732; Waste Gas (WG) Analyzers Loss of Function Due to Unit 2 RCS Leakage
- IR 02669741; RCDT Pressure Indicator Pegged High (2RE–1004)
- IR 02669742; RCDT Pressure Indicator Pegged High (2RE–1058)
- IR 02669753; B2R19 Inspect and Repair Valve 2RC8037A As Necessary
- IR 02669755; B2R19 Inspect and Repair Valve 2RC8032 As Necessary
- IR 02669759; B2R19 Inspect and Repair Valve 2CV8350 As Necessary
- IR 02669761; B2R19 Inspect and Repair Control Loops for the 2RE01T As Necessary
- IR 02669775; B2R19 Extent of Condition Review 2PC–NT094
- IR 02669781; 0A GW Compressor 0GW01SA Water/Steam Bound
- IR 02669782; 0B GW Compressor 0GW01SB Water/Steam Bound
- IR 02669787; Unit 1 and Unit 2 RCDT Pressure Computer points Poor
- IR 02669791; Unit One RCDT Pressure Elevated Post Unit 2 Event Use BOPRE6
- IR 02669794; Active Leakage on 2RE9161B
- IR 02669796; Pipe Cap Leak Downstream of 2RE002
- IR 02669799; Visible External Damage of 2RE9161A
- IR 02669800; Visible External Damage of 2RE9173B
- IR 02669801; Visible External Damage of 2RE9154
- IR 02670066; Evaluate Potential Need for LLRT (2RE9159A)
- IR 02670068; Evaluate Potential Need for LLRT (2RE9159B)
- IR 02670071; Evaluate Potential Need for LLRT (2RE9160A)
- IR 02670074; Evaluate Potential Need for LLRT (2RE9160B
- IR 02670077; Evaluate Potential Need for LLRT (2RE1003)
- IR 02670078; Evaluate Potential Need for LLRT (2RE9170)
- IR 02670093; 0A GW Compressor
- IR 02670104; Evaluate Potential Need for LLRT (2RE9157)
- Exelon Event Summary Report, dated May 16, 2016;
- M–135, Sheet 1A, Revision AW; Diagram of Reactor Coolant Loop – 1
- M–138, Sheet 2; Revision AN; Diagram of Chemical & Volume Control & Boron Thermal Regeneration Unit 2
- M–141, Sheet 1, Revision AG; Diagram of Reactor Building Containment Equipment Drains & Vents to Radwaste

- M–135, Sheet 1B, Revision BD; Diagram of Reactor Coolant Loop 1
- Event Notification 51931; Unusual Event Declared Due to Excessive Unidentified Leakage During Plant Startup
- Exelon Letter RS–12–156, Attachment 2, dated October 25, 2012; Byron Station, Units 1 and 2 Response to NRC Bulletin 2012-01, “Design Vulnerability in Electric Power System”
- Exelon Letter RS–14–027, Attachment 2, dated February 3, 2014; Byron Station, Units 1 and 2 Additional Information Regarding Response to NRC Bulletin to NRC Bulletin 2012-01, “Design Vulnerability in Electric Power System”
- LERs 05000454/2012–001, Revision 00 and Revision 01, “Unit 2 Loss of Normal Offsite Power and Reactor Trip and Unit 1 Loss of Normal Offsite Power Due to Failure of System Auxiliary Transformer Inverted Insulators”
- IR 01319908; Byron Station Unit 2 Reactor Trip and Loss of Offsite Power
- IR 01320006; B2F26 Unit 2 Trip SAT C-Phase Found Open
- EC 389896; SAT Loss of Phase Relay Installation

4OA5 Other Activities

- Byron Station Units 1 and 2 - NRC Component Design Bases Inspection; Inspection Report 05000454/2015008; 05000455/2015008 and Notice of Violation; dated July 21, 2015
- Exelon Letter, Byron 2015–0097 from F.A. Kearney to US NRC; Reply to a Notice of Violation; 05000454/2015008-09; 05000455/2015008-09
- NRC Letter from Christine Lipa to Bryan Hanson dated September 4, 2015; Acknowledgement of Reply to Notice of Violation 05000454/2015–09; 05000455/2015008–09; Dated August 20, 2015; Byron Station Units 1 and 2
- DRP 16–018, UFSAR Change Package (including 50.59 Screening) for pages 6.3–16, 6.3–19, and 6.3–53a
- IR 01378257; CDBI Question About ECCS Leakage
- IR 01398434; NRC CDBI Green NCV – Leak Detection for ECCS Flow Path Lacking
- IR 02454767; NOS ID: No CA to Correct an NRC NCV
- IR 02496802; Prepare, Review, and/or Approve UFSAR DRP 16–018
- EC 394194, Revision 00; HELC Document Changes for Byron Unit 1 and 2
- EC 402053, Revision 001; ECCS Leakage in Auxiliary Building While on Recirculation
- SECY–77–439, dated August 17, 1977; “Single Failure Criterion”

4OA7 Licensee-Identified Violations

- IR 02639686; Ops Focus, Ops Gaps to Excellence
- OP–MW–201–007, Revision 7; Fire Protection System Impairment Control
- Unit 1/2 Standing Order 15–033, dated 08/20/15; Potential Hot Short during Fire Could Cause Safe S/D Equipment Inoperability
- Unit 1/2 Standing Order 15–033, dated 03/15/16; Potential Hot Short during Fire Could Cause Safe S/D Equipment Inoperability

LIST OF ACRONYMS USED

∆CDF	Delta Core Damage Frequency
AB	Auxiliary Building
ADAMS	Agencywide Document Access Management System
AF	Auxiliary Feedwater
ALARA	As-Low-As-Is-Reasonably-Achievable
AOP	Abnormal Operating Procedure
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CB&I	Chicago Bridge & Iron
CFR	Code of Federal Regulations
CST	Condensate Storage Tank
CV	Volume Control System
DRP	Division of Reactor Projects
EGM	Enforcement Guidance Memorandum
ESF	Engineered Safety Feature
ET	Exposure Time
FLEX	Flexible Coping Strategy
FP	Fire Protection
FSAR	Final Safety Analysis Report
GDC	General Design Criteria
HELB	High Energy Line Break
HEP	Human Error Probability
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IPEEE	Individual Plant Examination of External Events
IR	Inspection Report
IR	Issue Report
ISI	Inservice Inspection
IST	Inservice Testing
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LERF	Large Early Release Frequency
LHRA	Locked High Radiation Area
LLRT	Local Leak Rate Testing
LOOP	Loss of Off-site Power
LTOP	Low Temperature Overpressure
NCV	Non-Cited Violation
NRC	U.S. Nuclear Regulatory Commission
PI	Performance Indicator
PM	Planned or Preventative Maintenance
PSF	Performance Shaping Factor
PWR	Pressurized Water Reactor
RASP	Risk Assessment Standardization Project
RCDT	Reactor Coolant Drain Tank
RCS	Reactor Coolant System
RFO	Refueling Outage
RWP	Radiation Work Permit
RWST	Reactor Water Storage Tank
SAT	System Auxiliary Transformers

SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection
SPAR	Standardize Plant Analysis Risk
SRA	Senior Reactor Analyst
SSC	System, Structure, and Component
TCCP	Temporary Configuration Change Package
TIA	Task Interface Agreement
TLCO	Technical Requirements Manual Limiting Condition for Operation
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Testing
Vac	Volts Alternating Current
VC	Control Room Ventilation
VIO	Notice of Violation
WO	Work Order

If you contest the violations or significance of the NCVs, 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 copies to: (1) the Regional Administrator, Region III; (2) the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; and (3) the NRC Resident Inspector at the Byron Station.

In addition, if you disagree with the cross-cutting aspect assignment to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Byron Station.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, “Public Inspections, Exemptions, Requests for Withholding,” of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC’s Public Document Room or from the Publicly Available Records System (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA Jamnes Cameron Acting for/

Eric Duncan, Chief
Branch 3
Division of Reactor Projects

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IR 05000454/2016002; 05000455/2016002

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Letter to B. Hanson from E. Duncan dated July 26, 2016

SUBJECT: BYRON STATION, UNITS 1 AND 2 — NRC INTEGRATED INSPECTION REPORT 05000454/2016002; 05000455/2016002 AND EXERCISE OF ENFORCEMENT DISCRETION

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