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

February 10, 2015

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

SUBJECT: RE-ISSUED INSPECTION REPORT: BYRON STATION, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000454/2014005; 05000455/2014005

Dear Mr. Hanson:

On February 5, 2015, the U.S. Nuclear Regulatory Commission (NRC) issued Inspection Report 05000454/2014005; 05000455/2014005 and this report is publicly available under Agencywide Documents Access and Management System (ADAMS) Accession Number ML15036A527. After the inspection report was issued, the NRC identified that a report input documenting completion of inspection activities conducted in accordance with Inspection Procedure 71111.04 was not properly documented. The cover letter and the enclosed inspection report are being re-issued to correct the inspection record.

On December 31, 2014, the NRC completed an inspection at your Byron Station, Units 1 and 2. On January 6, 2015, the NRC inspectors discussed the results of this inspection with the Site Vice President, Mr. R. Kearney, and other members of your staff. The inspectors documented the results of this inspection in the enclosed inspection report.

NRC inspectors documented five findings of very low safety significance (Green) in this report. Four of these findings involved violations of NRC requirements. Further, inspectors documented licensee-identified violations in Section 4OA7 of this report, which were determined to be of very low safety significance. The NRC is treating these violations as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

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

If you disagree with the cross-cutting aspect assigned 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 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 (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/

John Ellegood, Acting Chief
Branch 3
Division of Reactor Projects

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

Enclosure:
IR 05000454/2014005; 05000455/2014005
w/Attachment: Supplemental Information

cc w/encl: Distribution via LISTSERV®

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000454; 05000455
License Nos:	NPF–37; NPF–66
Report No:	05000454/2014005; 05000455/2014005
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	Byron, IL
Dates:	October 1 through December 31, 2014
Inspectors:	J. McGhee, Senior Resident Inspector J. Draper, Resident Inspector T. Bilik, Reactor Inspector M. Holmberg, Senior Reactor Inspector R. Jickling, Senior Emergency Preparedness Inspector J. Cassidy, Senior Health Physicist M. Bielby, Operator Licensing Lead Inspector R. Baker, Operator Licensing Inspector C. Thompson, Resident Inspector, Illinois Emergency Management Agency
Approved by:	J. Ellegood, Acting Chief Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report 05000454/2014005, 05000455/2014005; [10/01/2014–12/31/2014]; Byron Station, Units 1 and 2; Inservice Inspection Activities, Operability Determinations, and Outage Activities.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Five Green findings were identified by the inspectors. Four of the findings were considered non-cited violations (NCVs) of NRC regulations. 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 (SDP)" dated June 2, 2011. 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 July 9, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process" Revision 5, dated February 2014.

NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion IX, "Control of Special Processes," for a failure to measure the interpass temperature while performing welding on the on the safety injection (SI) piping system. Consequently, welding was performed without the Code and procedure required interpass temperature being monitored on a number of welds, a parameter which can affect the mechanical properties of the material being welded. After identification of the issue, the welders restored compliance by measuring the interpass temperatures on the balance of the welds and verifying that the interpass temperature did not exceed that allowed by procedure. The licensee entered this issue into its Corrective Action Program (CAP) (IR 02391545).

  The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because the inspectors answered "Yes" to the More-than-Minor question, "If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, absent NRC intervention, the welders would have completed all of the welds without having measured the interpass temperature, a welding parameter which can affect the mechanical properties (e.g., impact properties) of some materials being welded, and if left uncorrected, could lead to a potential failure of the weld in service. In accordance with Table 2, "Cornerstones Affected by Degraded Condition or Programmatic Weakness," of IMC 609, Attachment 4, "Initial Characterization of Findings," issued June 19, 2012, the inspectors checked the box under the Mitigating Systems Cornerstone because leakage on the SI piping system could degrade short term heat removal. The inspectors determined this finding was of very-low safety significance (Green) using Part A of Exhibit 2, "Mitigating Systems Screening Questions," in IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued on June 19, 2012. Specifically, the inspectors answered "Yes" to the screening question "If the finding is a deficiency affecting the design or qualification of a mitigating Systems Structures and Components (SSC), does the SSC maintain its operability or functionality?" The welders proceeded to measure the interpass temperatures on the balance of the welds and verified that the interpass temperature did not exceed that allowed by procedure, and the issue did not result in the actual loss of the operability or functionality of a safety system. The finding had a cross-cutting aspect of Procedure Adherence in the area of Human Performance (IMC 0310 H.8). Specifically, the welders failed to follow procedures. (Section 1R08.b(1))

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion IX, "Control of Special Processes," for the failure to perform a Liquid Penetrant Test (PT) in accordance with the American Society for Mechanical Engineers (ASME) Code while performing a surface examination on reactor coolant pump (RCP) flywheel 2A/D483. The vendor conducted a demonstration in an attempt to show the differences in bleed-out between the two dwell times, to demonstrate continued functionality of the flywheel. The results showed little if any difference in the growth of the bleed-out given the additional time. The licensee was developing an action plan to address the non-conformance and restore compliance. The issue was entered into the licensee's CAP as IR 02393595 and IR 02399248.

  The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because the inspectors answered "Yes" to the More-than-Minor question, "If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, since the liquid penetrant testing developer minimum dwell time may not have been met, the liquid penetrant examination was not assured to accurately measure a rejectable flaw. Absent NRC intervention, the potential would exist for a rejectable flaw to remain in service, affecting the operability of affected systems. In accordance with Table 2, "Cornerstones Affected by Degraded Condition or Programmatic Weakness," of IMC 609, Attachment 4, "Initial Characterization of Findings," issued June 19, 2012, the inspectors checked the box under the Mitigating Systems Cornerstone because failure of the RCP flywheel could degrade core decay heat removal. The inspectors determined this finding was of very-low safety significance (Green) using Part A of Exhibit 2, "Mitigating Systems Screening Questions," in IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued on June 19, 2012. Specifically, the issue did not result in the actual loss of the operability or functionality of a safety system; and therefore the inspectors answered "Yes" to the screening question "If the finding is a deficiency affecting the design or qualification of a mitigating SSC, does the SSC maintain its operability or functionality?" The vendor subsequently performed demonstrations to show that the bleed-out from an indication would not change appreciably when implementing the additional dwell time. The licensee was still evaluating its planned corrective actions. However, the inspectors determined that the continued non-compliance did not present an immediate safety concern because the licensee/vendor reasonably determined the RCP flywheel remained functional. The finding had a cross-cutting aspect of Change Management in the area of Human Performance (IMC 0310 H.3) in that leaders failed to use a systematic process for evaluating and implementing change so that nuclear safety remains an overriding priority. Specifically, the licensee failed to ensure that the vendor changed its procedure to reflect the requirements of the current edition of the ASME Code adopted by the licensee. (Section 1R08.b(2))

- Green. The inspectors identified a finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion IX, "Control of Special Processes," for the failure to revise or amend a welding procedure specification (WPS) after changing welding variables, including an increase in amperage, for welding performed on the SI system. The licensee interviewed the welders who indicated that they would likely not have increased the amperage to the range permitted, to restore compliance. The licensee planned to review the use of vendor technical information (VTIP) manual information for welding criteria and cover this issue with the work order planners. Also, the site welding administrator planned to review the issue to be aware of possible WPS deviations in work instructions. The issue was entered into the licensee's CAP as IR 02392483.

  The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because the inspectors answered "Yes" to the More-than-Minor question, "If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, the welding variables were changed without appropriate process or documentation, or meeting ASME Code, which resulted in the permitted use of a significant increase in amperage above that in the WPS. This permitted the welders to use an elevated heat input which could have been detrimental to the components being welded. In accordance with Table 2, "Cornerstones Affected by Degraded Condition or Programmatic Weakness," of IMC 609, Attachment 4, "Initial Characterization of Findings," issued June 19, 2012, the inspectors checked the box under the Mitigating Systems Cornerstone because degradation of the SI system could degrade short term heat removal. The inspectors determined this finding was of very-low safety significance (Green) using Part A of Exhibit 2, "Mitigating Systems Screening Questions," in IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued on June 19, 2012. Specifically, the inspectors answered "Yes" to the screening question "If the finding is a deficiency affecting the design or qualification of a mitigating SSC, does the SSC maintain its operability or functionality?" The welders indicated that they would likely not have used the elevated heat inputs; and therefore, would still comply with the original WPS, and the issue did not result in the actual loss of the operability or functionality of a safety system. The finding had a cross-cutting aspect of Documentation in the area of Human Performance (IMC 0310 H.7). Specifically, the organization failed to create and maintain complete, accurate and up-to-date documentation. (Section 1R08.b(3))

- Green. Inspectors identified a finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions Procedures, and Drawings," for failure to implement procedure OP-AA-108-115, "Operability Determinations (CM-1)," as written when a degraded condition was identified for a non-TS SSC that supported a TS SSC. Specifically, during a surveillance test of the flood barrier door to the 2B emergency diesel generator (EDG) fuel oil storage tank room in March 2014, maintenance technicians identified a degraded condition that, while not affecting immediate functionality of the barrier, was identified to have the potential to impact the door functionality prior to the next scheduled performance of the surveillance. An Operability Determination was not performed for the supported TS SSCs at that time as required by OP–AA–108–115 and in June of 2014 (the next surveillance performance), the door failed the test, and both Unit EDGs were declared inoperable. The issue was entered in the CAP as Issue Report (IR) 1675255. Upon discovery of the failure of the water-tight door, a temporary water-tight barrier was immediately installed, restoring operability of the Unit 2 EDGs. The permanent water-tight door was repaired and returned to service at a later date.

Failure to perform and document an operability determination of the Unit 2 EDGs and fuel oil transfer pumps upon discovery of the degraded condition of the support system (i.e., flood barrier door) is a performance deficiency. The finding was more than minor because, if left uncorrected, failure to evaluate operability through a SSC's surveillance interval can lead to more significant safety concerns and an unevaluated assumption of risk by the station. The finding affected the Mitigating Systems Cornerstone because it impacted an External Events Mitigation System (degraded flood protection). Because a complete loss of the water-tight door could impact both Unit 2 EDG trains, the NRC Senior Reactor Analysts (SRAs) performed a more detailed significance determination and determined that the finding was not greater than Green. The finding had a cross-cutting aspect of Conservative Bias in the area of Human Performance (IMC 0310 H.14) because the licensee's decisions regarding disposition of the degraded condition did not indicate a conservative bias that emphasized prudent choices over those that were allowable. Even though mechanics identified the potential for the condition to degrade further in the near future, the work request was not given a high priority and continued functionality of the door was not evaluated through the next surveillance period by the licensee. (Section 1R15)

Cornerstone: Barrier Integrity

- Green. Inspectors identified a finding of very low safety significance when the licensee impaired a flood protection boundary that supported a required safety function for operational convenience. Specifically, the licensee removed the flood barriers for auxiliary feedwater system containment isolation valves and rendered the valves inoperable prior to the plant reaching Mode 5 and thereby entered TS 3.6.3 Condition C for operational convenience contrary to the TS Bases associated with TS 3.0.2 Limiting Condition for Operability (LCO) Applicability. From 2010 on September 28, 2014, until 0536 on September 29, 2014, while transitioning from Mode 1 to Mode 5, the valves were rendered inoperable. This issue has been entered in the CAP as IR 2390265. Corrective actions included Senior Reactor Operator review of the LCO basis and creating a logic tie in the outage schedule template tying the barrier removal to Mode 5.

  The finding was more than minor because it impacted the SSC and Barrier Performance attribute of the Barrier Integrity Cornerstone, and adversely affected the cornerstone objective to provide reasonable assurance that the physical design barrier of the containment system protects the public from radionuclide releases caused by accidents or events. Specifically, with inoperable containment isolation valves the potential for an open containment pathway is increased. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, Appendix A, "The Significance Determination Process For Findings At-Power," Exhibit 3–Barrier Integrity Screening Questions, item B for the Reactor Containment. Both questions were answered "No" and therefore the finding screened as Green. The finding had an associated cross-cutting aspect of Work Management in the area of Human Performance (MC 0310 H.5) because the shutdown and outage work schedules did not contain the rigor required to ensure the isolation valves were maintained operable as required by TS. (Section 1R20)

Licensee Identified Findings

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

Unit 1

The unit began the period at full power and operated at or near full power until October 6 when power was lowered to 83.5 percent at the request of the transmission operator to support planned switchyard maintenance. After the maintenance was completed on October 8, Unit 1 returned to full power and operated there until December 30, 2014. On December 30 Unit 1 power was lowered to approximately 73 percent to support a switchyard insulator repair. The insulator was repaired on December 31 and Unit 1 was ramped back up to full power where it operated for the remainder of the inspection period.

Unit 2

The unit began the period shutdown with refueling outage B2R18 in progress. Unit 2 exited the outage on October 23 and reached full power on October 26, 2014. The unit operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee’s preparations for winter conditions to verify that the plant’s design features and implementation of procedures were sufficient to protect mitigating systems from the effects of adverse weather. Documentation for selected risk-significant systems was reviewed to ensure that these systems would remain functional when challenged by inclement weather. 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. Cold weather protection, such as heat tracing and area heaters, was verified to be in operation where applicable. 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 due to their risk significance or susceptibility to cold weather issues:

- river screen house ventilation system (VH); and
- essential service water make-up pumps (SX).

This inspection constituted one winter seasonal readiness preparations sample as defined in inspection procedure (IP) 71111.01–05.

b. Findings

No findings were identified.

.2 External Flooding

a. Inspection Scope

The inspectors evaluated the design, material condition, and procedures for coping with the expected flooding conditions based on the most recent flooding hazard analysis postulated rainfall and rises in local river levels. The evaluation included a review to check for deviations from the descriptions provided in the UFSAR for features intended to mitigate the potential for flooding. As part of this evaluation, the inspectors checked for obstructions that could prevent draining, checked that the roofs did not contain obvious loose items that could clog drains in the event of heavy precipitation, and determined that barriers required to mitigate the flood were in place and operable. Additionally, the inspectors performed a walkdown of the protected area to identify any modification to the site which would inhibit site drainage during the predicted flood conditions or allow water ingress past a barrier.

This inspection constituted one external flooding 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:

- 1B auxiliary feed pump following maintenance activities;
- 2B centrifugal charging pump following return to service after maintenance; and
- 2A EDG starting air, fuel, and lube oil systems 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, UFSAR, technical specifications requirements, outstanding work orders (WO,) IRs, 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

On December 18, 2014, the inspectors performed a complete system alignment inspection of the Unit 2 residual heat removal (RH) system to verify the functional capability of the system following return to service after a system maintenance outage. 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, component labeling, component lubrication, equipment cooling, and piping hangers and supports. Operability of support systems was verified 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 availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- 2B EDG and day tank rooms (Fire Zones 9.1–2 and 9.4–2);
- 2A containment spray pump room (Fire Zone 11.2B–2);
- 2B containment spray pump room (Fire Zone 11.2A–2);
- 2A RH pump room (Fire Zone 11.2A–2); and,
- 2B RH pump room (Fire Zone 11.2B–2).

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 five quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R08 Inservice Inspection Activities (71111.08P)

From September 29, 2014, through October 10, 2014, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the reactor coolant system, steam generator tubes, emergency feedwater systems, risk significant piping and components and containment systems.

The inspections described in Sections 1R08.1, 1R08.2, R08.3, IR08.4 and 1R08.5 below constituted one inservice inspection sample as defined in IP 71111.08–05.

.1 Piping Systems Inservice Inspection

a. Inspection Scope

The inspectors either observed or reviewed the following non-destructive examinations mandated by the ASME Section XI Code 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 a NRC approved alternative requirement:

- ultrasonic (UT) examination of vessel head penetrations 13, 39, 44, 45, 64, and 72;
- UT of feedwater piping reducer–tee welds 1, 2, 3 and 7 of 2FW87CB–6/C01;
- magnetic particle (MT) examination of main steam restraint lugs for 2MS01AA–30.25/E–2;
- liquid penetrant (PT) examination of main steam restraint lugs for 2MS01AA–30.25/E–2;

- visual examination (VT–3) of component cooling system surge tank 2CC01T; and
- VT–3 of a safety injection restraint/support for 2SI15004X.

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

- indication UT disposition rejected during vessel weld (2RC–01–BA/SGC–08) examination in WO 1505231;
- indication UT disposition rejected during nozzle-to-shell weld (2RC–01–BB/SGN–03) examination in WO 1505231; and
- indication PT disposition rejected during flywheel (2RC–01–PC/Flywheel) examination in WO 1323963.

The inspectors either observed or reviewed the following pressure boundary welds completed for risk significant systems since the beginning of the last refueling outage to determine whether the licensee applied the pre-service non-destructive examinations and acceptance criteria required by the Construction Code and ASME Code, Section XI:

- weld repair/replacement of Class 1, of safety injection (SI) system loop 3 cold leg check valve (2SI8900C) per WO 01480596;
- weld repair/replacement of Class 1, of SI system loop 2 hot leg check valve (2SI8905B) per WO 01025526; and
- weld repair/replacement of SI system seal weld on Class 1 valve (2SI8819A) per WO 1478575.

Additionally, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to determine whether the weld procedures were qualified in accordance with the requirements of Construction Code and the ASME Code Section IX.

b. <u>Findings</u>

(1) <u>Failure to Measure Interpass Temperature</u>

<u>Introduction</u>: The inspectors identified a finding of very low safety significance, Green, and an associated NCV of 10 CFR Part 50, Appendix B, Criterion IX, “Control of Special Processes,” for a failure to measure the interpass temperature while performing welding on the SI piping system. Consequently, welding was performed without the code and procedurally required interpass temperature being monitored; a parameter which can potentially affect the mechanical properties of materials being welded.

<u>Description</u>: The inspectors observed that welders had failed to measure the interpass temperature while performing gas tungsten arc welding (GTAW) on SI system piping as part of the diverse and flexible coping strategies (FLEX) modification. The inspectors also noted that there were no temperature-measuring devices in the area.

The welders were to perform the welding activities in accordance with welding procedure specification (WPS) 1–1–GTSM–PWHT, which specified an interpass temperature limit to ensure that temperature was not exceeded on the work piece between passes.

Furthermore, Procedure MA–MW–796–101, “Welding, Brazing and Soldering Records,” and Procedure CC–AA–501–1011, “Exelon Nuclear Welding Program Preheat, Interpass Temperature and Postweld Heat Treatment of Welds,” used in conjunction with the WPS, required in part that “When interpass temperature is specified (on the WPS) **CHECK** the interpass temperature prior to initiating the arc for each pass using contact pyrometers, thermometers, or temperature indicating crayons.” These procedural provisions implemented Article 1 of ASME Section IX, which states that welding must be performed as established in the WPS.

Multiple passes had already been performed on a number of welds as part of the FLEX modification to the SI system before the inspectors observed the in-process welding and noted the failure to measure the interpass temperature. The inspectors were concerned that failing to follow procedures as required by the code and procedures, could impact the quality of the welds and lead to susceptible material failing while in service, and thereby adversely affect the integrity of the associated systems. As a result of the inspectors’ concern, the welders measured the interpass temperatures on the balance of the FLEX modification welds and verified that the interpass temperatures did not exceed that allowed by procedure. Since the measured interpass temperatures were well below that permitted by procedure, the inspectors concluded that there was reasonable assurance that the previous weld passes would not have exceeded the interpass temperature. The issue was entered into the licensee’s CAP as IR 02391545.

Analysis: The inspectors determined that the failure to measure the weld interpass temperature as required by the ASME Code Section IX and site procedures was a performance deficiency that warranted a significance evaluation. The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, “Issue Screening,” dated September 7, 2012, because the inspectors answered "Yes" to the More-than-Minor question, “If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?” Specifically, absent NRC intervention, the welders would have completed all of the welds without having measured the interpass temperature; a welding parameter which can affect the mechanical properties (e.g., impact properties) of some materials being welded, and if not corrected, could lead to a potential failure of welds in service.

In accordance with Table 2, “Cornerstones Affected by Degraded Condition or Programmatic Weakness,” of IMC 609, Attachment 4, “Initial Characterization of Findings,” issued June 19, 2012, the inspectors checked the box under the Mitigating Systems Cornerstone because leakage at this SI piping could degrade short term heat removal. The inspectors determined this finding was of very-low safety significance (Green) using Part A of Exhibit 2, “Mitigating Systems Screening Questions,” in IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” issued on June 19, 2012. Specifically, the inspectors answered "Yes" to the screening question “If the finding is a deficiency affecting the design or qualification of a mitigating SSC, does the SSC maintain its operability or functionality?” The welders subsequently performed interpass temperature measurements and demonstrated that the temperature would remain below the required temperature of the welds in question, and the issue did not result in the actual loss of the operability or functionality of a safety system.

The inspectors determined that the primary cause of the failure to measure the interpass temperature while performing a manual welding process was related to the cross-cutting aspect of Procedure Adherence in the Human Performance area (H.8). Specifically, the welders failed to follow procedures.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion IX, Control of Special Processes, states that, “Measures shall be established to assure that special processes, including welding, heat treating, and nondestructive testing, are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements.”

The WPS 1–1–GTSM–PWHT, used to perform welding on the Class 1, SI FLEX piping welds, includes an interpass temperature.

Welding Procedure MA–MW–796–101, “Welding, Brazing and Soldering Records,” requires in part that “When interpass temperature is specified (on the WPS) **CHECK** the interpass temperature prior to initiating the arc for each pass using contact pyrometers, thermometers, or temperature indicating crayons.”

Contrary to the above, while performing welding on the SI FLEX piping welds, the welders did not accomplish the welding in accordance with the WPS in that they failed to measure the interpass temperature. After identification by the inspectors, the welders proceeded to measure the interpass temperature on the balance of the welds, thereby providing reasonable assurance that interpass temperatures had not been exceeded.

Because of the very-low safety significance and because the licensee entered this issue into its CAP, it is being treated as a NCV consistent with Section 2.3.2 of the Enforcement Policy **(NCV 05000454/2014005–01, 05000455/2014005–01; “Failure to Measure Interpass Temperature”)**.

(2) Liquid Penetrant Testing Procedure Did Not Meet American Society of Mechanical Engineers Code

Introduction: The inspectors identified a finding of very low safety significance, Green, and an associated NCV of 10 CFR Part 50, Appendix B, Criterion IX, “Control of Special Processes,” for a failure to perform a PT examination in accordance with the ASME Code. Specifically, the liquid penetrant testing procedure used by the licensee’s vendor, for a RCP flywheel, had a developer dwell time less than that required by ASME Section V, “Nondestructive Examination.”

Description: The inspectors identified that vendor personnel had failed to employ the required ASME Code developer dwell time (7 minutes versus the required 10 minutes) while performing a PT Examination on RCP flywheel 2A/D483. The vendor that performed the RCP motor refurbishment conducted the required PT exam per its Procedure 80165, “PT Testing”. This was a generic PT procedure that was not specific to the current edition of the ASME Code the licensee was committed to, which resulted in the use of a dwell time less than required. The vendor’s liquid penetrant test report did not record actual dwell times. Hence, there was insufficient rationale to conclude that vendor examiners employed a dwell time longer than that stated in the procedure. In addition, a rounded indication was identified during the PT examination, which was dispositioned as acceptable since the “bleed-out” had not grown to a rejectable size. While the initial bleed-out occurs quite rapidly, some increase in the size of the indication can continue given sufficient dwell time. However, the indication measured was half that required to be rejectable, and hence, was likely not to have reached the rejectable threshold given the additional dwell time.

The vendor subsequently conducted a demonstration to show the effect on bleed-out between the two dwell times on a test flaw. The results showed little if any difference in the growth of the bleed-out given the additional time. The merits of the demonstration, though limited, when combined with the small size of the indication identified provided reasonable assurance to support the continued functionality of the flywheel. Also, the dwell time employed by the vendor was standard in an earlier edition of the Code. The licensee was developing an action plan to address the non-conformance. The issue was entered into the licensee's CAP as IRs 02393595 and 02399248.

Analysis: The inspectors determined that the failure to perform a PT examination in accordance with the requirements of ASME Section V was a performance deficiency that warranted a significance evaluation. The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because the inspectors answered "Yes" to the More-than-Minor question, "If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, since the liquid penetrant testing developer minimum dwell time may not have been met, the liquid penetrant examination did not provide the level of confidence implied by the Code with respect to the examination capability to identify a rejectable flaw. Absent NRC intervention, the potential would exist for a rejectable flaw to remain in service, potentially affecting the operability of affected systems.

In accordance with Table 2, "Cornerstones Affected by Degraded Condition or Programmatic Weakness," of IMC 609, Attachment 4, "Initial Characterization of Findings," issued June 19, 2012, the inspectors checked the box under the Mitigating Systems Cornerstone because failure of the RCP flywheel could degrade core decay heat removal. The inspectors determined this finding was of very-low safety significance (Green) using Part A of Exhibit 2, "Mitigating Systems Screening Questions," in IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued on June 19, 2012. Specifically, the issue did not result in the actual loss of the operability or functionality of a safety system; and therefore the inspectors answered "Yes" to the screening question "If the finding is a deficiency affecting the design or qualification of a mitigating SSC, does the SSC maintain its operability or functionality?" The vendor subsequently performed a demonstration to show that the bleed-out from an indication would not change appreciably when implementing the additional dwell time.

The licensee was still evaluating its planned corrective actions. However, the inspectors determined that the continued non-conformance did not present an immediate safety concern because the licensee/vendor reasonably determined the RCP flywheel remained functional.

The inspectors determined that the primary cause of the failure to perform a PT examination in accordance with ASME Code requirements was related to the cross-cutting aspect of Change Management in the Human Performance area (H.3) in that leaders failed to use a systematic process for evaluating and implementing change so that nuclear safety remains an overriding priority. Specifically, the licensee failed to ensure that the vendor changed its procedure to reflect the requirements of the current edition of the ASME Code adopted by the licensee.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion IX, Control of Special Processes, states that, "Measures shall be established to assure that special processes, including welding, heat treating, and nondestructive testing, are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements."

Appendix A, Paragraph f, Section C, Item 4b: "Inservice Inspection of Reactor Coolant Pump Flywheel," of the UFSAR, states that the inservice inspection of the exposed surfaces of the removed flywheel may be conducted with a surface examinations (MT and/or PT) and that the requirements for the examination procedures and the acceptance criteria as described in Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity," will be followed.

Paragraph C.4.b(3) of Regulatory Guide 1.14 states that "Examination procedures should be in accordance with the requirements of Subarticle IWA–2200 of Section XI of the ASME Code."

The 2001 Edition through the 2003 Addenda of ASME Section XI, IWA–2222, specifies that liquid penetrant examinations be performed to ASME Section V, Article 6.

Table T–672, of ASME Section V, Article 6, "Liquid Penetrant Examination," lists the minimum Code required dwell times for the PT process. The minimum developer dwell time was 10 minutes.

Contrary to the above, while performing a PT examination on RCP flywheel 2A/D483, a licensee vendor did not accomplish the nondestructive testing in accordance with applicable codes. Specifically, the vendor used a procedure that specified a developer dwell time of only 7 minutes versus the Code required 10 minutes, and hence there was insufficient basis to conclude that the required dwell time was met.

The vendor subsequently performed a demonstration to show that the bleed-out from an indication would not change appreciably when implementing the additional dwell time. It should be noted that the dwell time employed by the vendor was standard in an earlier edition of the ASME Code. The licensee was still evaluating its planned corrective actions to restore compliance. However, the inspectors determined that the continued non-conformance did not present an immediate safety concern because the licensee/vendor reasonably determined the RCP flywheel remained functional.

Because of the very-low safety significance and because the licensee entered this issue into its CAP, it is being treated as a NCV consistent with Section 2.3.2 of the Enforcement Policy **(NCV 05000454/2014005–02, 05000455/2014005–02, "Liquid Penetrant (PT) Testing Procedure Did Not Meet ASME Code").**

(3) Welding Procedure Specification Variables Changed Without Revision or Amendment Contrary to American Society of Mechanical Engineers Code

Introduction: The inspectors identified a finding of very low safety significance, Green, and an associated NCV of 10 CFR Part 50, Appendix B, Criterion IX, "Control of Special Processes," for a failure to revise or amend a WPS after changing welding variables. Specifically, welding variable changes, including an increase in allowed amperage, were made to work packages without amendment or revision to the applicable WPS for welding performed on the SI system.

Description: While reviewing welding related work-packages developed to replace/install small Kerotest valves, the inspectors identified that changes had been made to WPS 8–8–GTSM required non-essential variables without amendment or revision, which is contrary to the ASME Code. Specifically, the inspectors identified that numerous work packages used to install small Kerotest valves had a Kerotest valve vendor VTIP manual guidance document included in the work packages. The guidance was designed to change several welding variables in another application in order to control heat input. However, this guidance was not appropriate for the Kerotest valve work in that it conflicted with non-essential variables prescribed by WPS 8–8–GTSM. The inspectors' concern in this case was that the guidance supplied would actually permit an increase in heat input beyond that allowed by the WPS (guidance allowed 150 amps vs. WPS of 50 to 100 amps) and thus increased the chances of valve seat warping.

The addition of the guideline was inappropriate and it should not have been included in the work packages. The licensee characterized it as a legacy package preparation issue and a work package documentation issue; both programmatic issues, which have to be addressed. As an immediate corrective action, the licensee interviewed the welders who indicated that they would likely not have increased the welding amperage to the range permitted. In addition, the licensee planned to review the use of VTIP manual information for welding criteria and cover this issue with the work order planners. Also, the site welding administrator planned to review the issue to be aware of possible WPS deviations in work instructions. The issue was entered into the licensee's CAP as IR 02392483.

Analysis: Inspectors determined that the failure to change the WPS welding variables in the work packages without revision or amendment to the WPS was contrary to the ASME Code Section IX and was a performance deficiency that warranted a significance evaluation. The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because the inspectors answered "Yes" to the More-than-Minor question, "If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, the welding variables were changed without appropriate process or documentation, or meeting the ASME Code, which resulted in the permitted use of a significant increase in amperage above that in the WPS. This permitted the welders to use an elevated heat input, which could have been detrimental to the components being welded.

In accordance with Table 2, "Cornerstones Affected by Degraded Condition or Programmatic Weakness," of IMC 609, Attachment 4, "Initial Characterization of Findings," issued June 19, 2012, the inspectors checked the box under the Mitigating Systems Cornerstone because degradation of the SI system could degrade short term heat removal. The inspectors determined this finding was of very-low safety significance (Green) using Part A of Exhibit 2, "Mitigating Systems Screening Questions," in IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued on June 19, 2012. Specifically, the inspectors answered "Yes" to the screening question "If the finding is a deficiency affecting the design or qualification of a mitigating SSC, does the SSC maintain its operability or functionality?" The welders indicated that they would likely not have used the elevated heat inputs and therefore would still comply with the original WPS, and the issue did not result in the actual loss of the operability or functionality of a safety system.

The inspectors determined that the primary cause of the failure to revise or amend a WPS in accordance with ASME Code requirements was related to the cross-cutting aspect of Documentation in the Human Performance area (H.7). Specifically, the organization failed to create and maintain complete, accurate and, up-to-date documentation.

Enforcement: Title 10 CFR 50, Appendix B, Criterion IX, Control of Special Processes, states that, "Measures shall be established to assure that special processes, including welding, heat treating, and nondestructive testing, are controlled and accomplished by qualified personnel using qualified procedures in accordance with applicable codes, standards, specifications, criteria, and other special requirements."

Section IX, QW–256, of the ASME Code contains the welding variables for the gas tungsten-arc welding process. Section IX states in part that changes to non-essential variables are permitted as long as the WPS is revised or amended to address the non-essential variable change.

Contrary to the above, while replacing Kerotest check-valves in the SI system as part of WO 01480596 and other work packages, changes were made to non-essential variables without revising WPS 8–8–GTSM. Discussions with welders indicated that they would not likely have increased the welding current to the level permitted, and therefore the heat input would not have affected the valves installed.

Because this violation was of very-low safety significance and was entered into the licensee's CAP, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000454/2014005–03, 05000455/2014005–03; Welding Procedure Specification Variables Changed Without Revision or Amendment Contrary to ASME Code)**.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

A bare metal visual examination and a non-visual examination were required this outage pursuant to 10 CFR 50.55a(g)(6)(ii)(D).

The inspectors observed the bare metal visual examination conducted on the reactor vessel
head at each of the penetration nozzles 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). Specifically, to determine:

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

The inspectors observed a number of non-visual examinations conducted on the reactor vessel head penetrations to determine whether the activities were conducted in accordance with the requirements of ASME CC N–729–1 and 10 CFR 50.55a(g)(6)(ii)(D). Specifically, to determine:

a. if the required examination scope (volumetric and surface coverage) was achieved and limitations (if applicable were recorded), in accordance with the licensee procedures;
b. if the UT examination equipment and procedures used were demonstrated by blind demonstration testing;
c. for indications or defects identified, that the licensee documented the conditions in examination reports and/or entered this condition into the corrective action system and implemented appropriate corrective actions; and
d. for indications accepted for continued service, that 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.

The inspectors observed and reviewed records of welded repairs on the Unit 2 upper head penetration number 6 completed during the 2014 Unit 2 refueling outage to determine if the licensee applied the pre-service non-destructive examinations and acceptance criteria required by the construction Code, NRC approved Code Case, NRC approved Code relief request or the ASME Code Section XI. Additionally, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to determine if the weld procedure(s) used were qualified in accordance with the Construction Code and the ASME Code Section IX requirements. Discovery of this indication was documented in Licensee Event Report (LER) 05000455/2014–004–00; Byron Unit 2 Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzle Weld Indication Attributed to Primary Water Stress Corrosion Cracking. Additional discussion of this LER is included in Section 4OA3.2 of this report.

b. Findings

No findings were identified.

.3 Boric Acid Corrosion Control

a. Inspection Scope

The inspectors performed an independent walkdown of the reactor coolant system and related lines in the containment, which had received a recent licensee boric acid walkdown and verified whether the licensee's boric acid corrosion control visual examinations emphasized locations where boric acid leaks can cause degradation of safety significant components.

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

- 2CV8117; Dry Boric Acid on Valve;

- 2CV131; Body to Bonnet Leakage;
- 2SI01PA; Boric Acid Leak on Flange; and
- 2SI121A; Boric Acid Leak on Flange.

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

- IR 01613143; 2BR7006 Leaking;
- IR 01507509; 2AB022 Leak; and
- IR 01675385; 2FC01P Leak.

b. Findings

No findings were identified.

.4 Steam Generator Tube Inspection Activities

a. Inspection Scope

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

- in-situ SG tube pressure testing screening criteria used were consistent with those identified in the Electric Power Research Institute (EPRI) TR–1025132, Steam Generator In-Situ Pressure Test Guidelines and whether these criteria were properly applied to screen degraded SG tubes for in-situ pressure testing;
- the numbers and sizes of SG tube flaws/degradation identified was bound by the licensee's previous outage Operational Assessment predictions;
- the SG tube ET examination scope and expansion criteria were sufficient to meet the TS, and the EPRI 1013706, Pressurized Water Reactor SG Examination Guidelines: Revision 7;
- the SG tube ET examination scope included potential areas of tube degradation identified in prior outage SG tube inspections and/or as identified in NRC generic industry operating experience applicable to these SG tubes;
- the licensee identified new tube degradation mechanisms and implemented adequate extent of condition inspection scope and repairs for the new tube degradation mechanism;
- the licensee implemented repair methods which were consistent with the repair processes allowed in the plant TS requirements and to determine if qualified depth sizing methods were applied to degraded tubes accepted for continued service;
- the licensee implemented an inappropriate "plug on detection" tube repair threshold (e.g., no attempt at sizing of flaws to confirm tube integrity);
- the licensee primary-to-secondary leakage (e.g., SG tube leakage) was below 3 gallons-per-day or the detection threshold during the previous operating cycle;
- the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, Performance Demonstration for Eddy Current

Examination, of EPRI 1013706, Pressurized Water Reactor SG Examination Guidelines, Revision 7; and

- the licensee performed secondary side SG inspections for location and removal of foreign materials.

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

b. Findings

No findings 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.

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 November 2, 2014, the inspectors observed a crew of licensed operators in the plant's simulator during an evaluated simulator scenario for licensed operator requalification training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;

- oversight and direction from supervisors; and
- the ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

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

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

b. Findings

No findings were identified.

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

a. Inspection Scope

On October 23, 2014, the inspectors observed Unit 2 startup activities from refueling outage B2R18. This was an activity that required heightened awareness or was related to increased risk. 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 procedures;
- control board (or equipment) manipulations;
- oversight and direction from supervisors; and
- the ability to identify and implement appropriate TS actions.

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

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

b. Findings

No findings were identified.

.3 Biennial Written and Annual Operating Test Results (71111.11A)

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the Biennial Written Examination and the Annual Operating Test, administered by the licensee from September 17, 2014, through December 12, 2014, required by 10 CFR 55.59(a). The results were compared to the thresholds established in IMC 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process," to assess the overall adequacy of the licensee's Licensed Operator Requalification Training (LORT) Program to meet the requirements of 10 CFR 55.59.

This inspection constituted one annual licensed operator requalification examination results sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

.4 Biennial Review (71111.11B)

a. Inspection Scope

The following inspection activities were conducted during the weeks of November 24, 2014, and December 1, 2014, to assess: (1) the effectiveness and adequacy of the facility licensee's implementation and maintenance of its systematic approach to training (SAT) based LORT Program, put into effect to satisfy the requirements of 10 CFR 55.59; (2) conformance with the requirements of 10 CFR 55.46 for use of a plant referenced simulator to conduct operator licensing examinations and for satisfying experience requirements; and (3) conformance with the operator license conditions specified in 10 CFR 55.53. The documents reviewed are listed in the Attachment to this report.

- Licensee Requalification Examinations (10 CFR 55.59(c); SAT Element 4 as Defined in 10 CFR 55.4): The inspectors reviewed the licensee's program for development and administration of the LORT biennial written examination and annual operating tests to assess the licensee's ability to develop and administer examinations that are acceptable for meeting the requirements of 10 CFR 55.59(a).

  - The inspectors conducted a detailed review of week one and week five versions of the biennial requalification written examination to assess content, level of difficulty, and quality of the materials.

  - The inspectors conducted a detailed review of twelve Job Performance Measures (JPMs) (weeks one and five) and six scenarios (weeks one, three and five) to assess content, level of difficulty, and quality of the operating test materials.

  - The inspectors observed the administration of the annual operating test to assess the licensee's effectiveness in conducting the examinations, including the conduct of pre-examination briefings, evaluations of individual operator and crew performance, and post-examination analysis. The inspectors evaluated the performance of two simulator crews in parallel with the facility evaluators during four dynamic simulator scenarios, and evaluated various licensed crew members concurrently with facility evaluators during the administration of several JPMs.

  - The inspectors assessed the adequacy and effectiveness of the remedial training conducted since the last requalification examinations and the training planned for the current examination cycle, to ensure that they addressed weaknesses in licensed operator or crew performance identified during training and plant operations. The inspectors reviewed remedial training procedures and individual remedial training plans.

- Conformance with Examination Security Requirements (10 CFR 55.49): The inspectors conducted an assessment of the licensee's processes related to examination, physical security and integrity (e.g., predictability and bias), to verify compliance with 10 CFR 55.49, "Integrity of Examinations and Tests." The inspectors reviewed the facility licensee's examination security procedure, and observed the implementation of physical security controls (e.g., access restrictions and simulator I/O controls) and integrity measures (e.g., security agreements, sampling criteria, bank use, and test item repetition) throughout the inspection period.

- Conformance with Simulator Requirements (10 CFR 55.46): The inspectors assessed the adequacy of the licensee's simulation facility (simulator) for use in operator licensing examinations and for satisfying experience requirements. The inspectors reviewed a sample of simulator performance test records (e.g., transient tests, malfunction tests, scenario based tests, post-event tests, steady state tests, and core performance tests), simulator discrepancies, and the process for ensuring continued assurance of simulator fidelity in accordance with 10 CFR 55.46. The inspectors reviewed and evaluated the discrepancy corrective action process to ensure that simulator fidelity was being maintained. Open simulator discrepancies were reviewed for importance relative to the impact on 10 CFR 55.45 and 55.59 operator actions as well as on nuclear and thermal hydraulic operating characteristics.

- Conformance with Operator License Conditions (10 CFR 55.53): The inspectors reviewed the facility licensee's program for maintaining active operator licenses to assess compliance with 10 CFR 55.53(e) and (f). The inspectors reviewed the procedural guidance and the process for tracking on-shift hours for licensed operators, and which control room positions were granted watch-standing credit for maintaining active operator licenses. Additionally, medical records for ten licensed operators were reviewed for compliance with 10 CFR 55.53(I).

- Problem Identification and Resolution (10 CFR 55.59(c); SAT Element 5 as defined in 10 CFR 55.4): The inspectors evaluated the licensee's ability to assess the effectiveness of its LORT program and their ability to implement appropriate corrective actions to maintain its LORT Program up-to-date. The inspectors reviewed documents related to the plant's operating history and associated responses (e.g., Plant Issues Matrix (PIM) and Plant Performance Review reports; recent examination and inspection reports; and LERs. The inspectors reviewed the use of feedback from operators, instructors, and supervisors, as well as the use of feedback from plant events and industry experience information. The inspectors reviewed the licensee's quality assurance oversight activities, including licensee training department self-assessment reports.

This inspection constituted one biennial licensed operator requalification program inspection 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:

- non-essential service water system;
- auxiliary building heating, ventilation, and cooling system; and
- the ultimate heat sink temperature control system.

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

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the Maintenance Rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for 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 three quarterly maintenance effectiveness samples as defined in IP 71111.12–05.

b. Findings

No findings were identified.

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

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:

- outage schedule week 2 and Unit 1 on-line risk impact of switchyard work activities;
- outage schedule revision 1;
- Unit 2 transition to Mode 3 and on-line risk evaluation with TS equipment out of service; and
- an emergent switchyard insulator failure and Unit 1 system auxiliary transformer maintenance outage.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. 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 four samples as defined in IP 71111.13–05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- corrosion found in Unit 2 reactor head stud hole number 11;
- flexible hose static bend radius is less than minimum criteria;
- abnormal physical conditions in new Battery 212 cells;
- missed half-trip surveillances for Unit 1 power range nuclear instruments;
- specific gravity results for 125-volt Division 212 battery less than acceptance criteria; and
- the degraded condition of 2B diesel oil storage tank water-tight door.

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

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

b. Findings

Introduction: Inspectors identified a finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions Procedures, and Drawings,” for failure to implement procedure OP–AA–108–115, “Operability Determinations (CM–1),” when a degraded condition was identified for a non-TS SSC that supported a TS SSC. Specifically, during a surveillance test of the flood barrier door to the 2B EDG fuel oil storage tank room in March 2014, maintenance technicians identified a degraded condition that, while not affecting immediate functionality, could degrade and impact door functionality prior to the next performance of the surveillance. The licensee did not perform an Operability Determination for the supported TS SSCs at that time as required by the procedure. During the next surveillance June of 2014 the door failed the test, rendering Unit 2 EDGs inoperable.

Description: On March 25, 2014, the licensee performed a water-tight door inspection on door 0DSSD194, the door to the 2B EDG fuel oil storage tank room. This door provides a flood barrier to prevent flood waters in the turbine building from affecting both Unit 2 trains of the EDG fuel oil transfer pumps, which are required for operability of the Unit 2 EDGs. The door satisfactorily passed the surveillance, including a chalk test; however during the performance of the inspection, mechanical maintenance identified a degraded condition. The issue was entered into the CAP as IR 1638185 and documented, “the general condition of the gearbox linkages and bushings, and adjustment screws, while acceptable per the criteria at this time, will prevent the door from passing in the near future.” Additionally, the completed work order package contained the comment that the IR was written to document issues with the door “that may not allow it to pass next time.” Operations reviewed the IR and documented the door as “functional as a flood barrier” but no basis was provided to support the assessment or the potential for further degradation to cause the door to fail “in the near future” as stated in the IR. The IR was closed to a work request, but no work was performed on the door before the next surveillance was performed.

The licensee’s operability determination procedure, OP–AA–108–115, includes requirements in Attachment 4 for actions to take when an immediate functionality assessment is performed for a non-TS SSC which supports an SSC described in TS. The procedure states that operability must also be addressed. Step 1.2 of OP–AA–108–115 states in part, “whenever the ability of an SSC to perform its specified safety function is called into question, operability must be determined from a detailed examination of the deficiency.” No operability assessment was documented in the IR for the affected TS SSCs.

NRC IMC 0326, “Operability Determinations & Functionality Assessments for Conditions Adverse to Quality or Safety,” describes NRC expectations for operability determinations and functionality assessments. This document states:

> "Satisfactory performance of TS surveillances is usually considered sufficient to demonstrate operability. However, if conformance to criteria in the current

licensing bases (CLB) that are both necessary and sufficient to establish operability cannot be established with reasonable expectation, then performance of the surveillance requirement may not, by itself, be sufficient to demonstrate operability. Failure to conform to CLB criteria that are not needed to demonstrate operability should be addressed by the appropriate licensee process. An example of when surveillances would not be sufficient to establish operability is the satisfactory completion of TS surveillance but with results that show a degrading trend and indicate that acceptance criteria might not be met before the next surveillance test. In this case, the surveillance actually identifies the conditions when the SSC will become inoperable and an operability evaluation would be warranted."

On June 25, 2014, the licensee again performed an inspection on door 0DSSD194 as it has a 92-day surveillance interval. During this performance of the surveillance, mechanical maintenance performed a chalk test on the door seal to verify the door was adequately closing. This time, the door did not pass the chalk test, so the door did not meet the surveillance acceptance criteria. Because this door was a flood barrier for both Unit 2 EDG fuel oil transfer pump trains, operations declared both Unit 2 EDGs inoperable, which forced the licensee to enter a 2 hour required action statement to return one EDG to operable status in accordance with TS LCO 3.8.1 Condition F.1 for two EDGs inoperable, or to shut down the reactor in accordance with TS LCO 3.8.1 Condition G if the 2 hour time limit was exceeded. The licensee's immediate corrective action was to install a pre-staged temporary flood barrier on the doorway to return both Unit 2 EDGs to operable status before 2 hours had passed.

Subsequent to the June surveillance failure, the licensee performed an analysis and determined that a rapid turbine building flooding event would flood to a level several feet above door 0DSSD194 such that the resultant force on the door would close up the gap between the door and the door frame before the flood waters could impact the fuel oil transfer pumps of the opposite train EDG. Therefore, the licensee concluded that the 2A EDG remained operable/available and the safety function of emergency power was never lost.

<u>Analysis</u>: The inspectors determined that the licensee's failure to perform and document an operability determination of the Unit 2 EDGs upon discovery of the degraded condition of the support system (i.e., flood barrier door) is a performance deficiency. Specifically, after the licensee identified the condition adverse to quality (e.g., degraded condition of door 0DSSD194) on March 25, 2014, that could potentially continue to degrade to impact the supported safety function before the next surveillance test, the licensee documented that the door was functional but no basis was provided to support that assessment as required by OP–AA–108–115. Additionally, the licensee failed to evaluate the operability of the EDGs through the surveillance interval of the water-tight door even though mechanics identified that the door might not pass its next surveillance. The inspectors determined that this performance deficiency was of more than minor safety significance because, if left uncorrected, the performance deficiency would have the potential to lead to a more significant safety concern. Specifically, the licensee's failure to evaluate the operability of SSCs when their acceptance criteria might not be met through the surveillance interval led to an avoidable inoperability of both Unit 2 EDGs. The inspectors determined that this finding impacted the Mitigating Systems cornerstone because it was an External Events Mitigation System (degraded flood protection). The inspectors utilized Exhibit 2, "Mitigating Systems Screening Questions,"

of IMC 0609, Appendix A, "The Significance Determination Process For Findings At-Power," dated June 19, 2012, to evaluate the significance. Because the inspectors determined that the finding involved the degradation of equipment specifically designed to mitigate a flooding event, the inspectors used Exhibit 4, "External Events Screening Questions," of the same Appendix to evaluate the significance. The inspectors determined that if the flood door were assumed to be completely failed, this condition by itself during a turbine building flood event would degrade two or more trains of a multi-train system. Specifically, the turbine building flood would impact the diesel fuel transfer pumps for both Unit 2 emergency diesel generators. Therefore, a Detailed Risk Evaluation was required.

To evaluate this finding, the SRAs determined two cases that would require evaluation to determine the risk significance of the finding. In Case 1, a random break in either the circulating water (CW) piping or the CW expansion joints of the main condenser results in a reactor trip, followed by a consequential loss of offsite power (LOOP) on the affected Unit, followed by a consequential LOOP on the other Unit. In Case 2, a seismic event results in a LOOP on both Units and a failure of either the CW piping or the CW expansion joints.

<u>Case 1</u>: Random Break in CW Piping or CW Expansion Joints Followed by Dual Unit LOOP

The frequency of a break in either the CW piping or the CW expansion joints was evaluated using EPRI Report 3002000079, "Pipe Rupture Frequencies for Internal Flooding Probabilistic Risk Assessments," Revision 3. Using Table ES–2 in the EPRI report, the following failure rate information was obtained:

System	Description	Value
CW Piping	Frequency of Piping Break Causing a Major Flood (i.e., greater than 2000 gpm leak)	7.95E–7/yr/foot
CW Expansion Joints	Frequency of Major Flood (i.e., greater than 2000 gpm leak) with flood rate ≤ 10,000 gpm	9.17E–6/yr/EJ
	Frequency of Major Flood with flood rate ≥ 10,000 gpm	6.08E–6/yr/EJ
	Total Frequency of CW Expansion Joint Major Flood	1.53E–5/yr/EJ

The following information and assumptions were used to obtain the frequency of a major flooding event in the turbine building due to a break in either the CW piping or the CW expansion joint:

- as obtained from the licensee, there is approximately 550 feet of CW piping per Unit in the turbine building (i.e., 1100 feet total);
- there are eight CW expansion joints per Unit; and
- a flooding event on either Unit will affect both Units.

Using the above information, the initiating event frequency (IEF) of a major flooding event in the turbine building due to a break in either the CW piping or the CW expansion joint is given by:

IEF = [(7.95E–7/yr/ft) x (550 ft/Unit) + (1.53E–5/yr/EJ) x (8 EJs/Unit)] x [2 Units]
= 1.12E–3/year

The Byron Standardized Plant Analysis Risk (SPAR) model version 8.27 and Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) version 8.1.0 software was used to obtain the probability of a dual Unit LOOP following a reactor trip. From the SPAR model, the following information was obtained:

SPAR Model Designation	Description	Value
ZT–VCF–LP–GT	Probability of a LOOP Given a Reactor Trip	5.29E–3
ZT–LOOP–SITE–SC	Probability of a Dual Unit LOOP (Switchyard-Centered)	1.146E–1

The exposure time for the finding was assessed to be three months, from March 25 through June 25, 2014. Using the above information, the probability of a Dual Unit LOOP (DLOOP) following a reactor trip is obtained as:

DLOOP = [ZT–VCF–LP–GT] x [ZT–LOOP–SITE–SC]
= [5.29E–3] x [1.146E–1]
= 6.1E–4

Taking into account that the exposure time is three months (0.25 years), and assuming that a Dual Unit LOOP with a failure of both emergency diesel generators (EDGs) would result in a core damage event, the delta core damage frequency (∆CDF) for Case 1 is obtained as the product of the following factors:

<u>Case 1</u>: ∆CDF= [IEF] x [DLOOP] x [Exposure Time]
= [1.12E–3/yr] x [6.1E–4] x [0.25]
= 1.7E–7/yr

<u>Case 2</u>: Seismic Event That Results in a DLOOP and a Break in CW Piping or CW Expansion Joints

A seismic event can result in the failure of either the CW piping or the CW expansion joints resulting in turbine building flooding. It is expected that a seismic event will also result in a DLOOP. Since DLOOP is a consequence of the initiator, the emergency diesel generator function is required. To obtain a bounding estimate of the delta ΔCDF, the frequency of a seismic event sufficient to cause plant damage is multiplied by the probability of failure of either the CW piping or the CW expansion joints due to the seismic event.

Using guidance from NRC's Risk Assessment Standardization Project (RASP) handbook, only the "Bin 2" seismic events were assumed to represent a ΔCDF. "Bin 2" is defined in the RASP handbook as seismic events with intensities greater than 0.3g but less than 0.5g. Earthquakes of lesser severity are unlikely to result in large pipe failures and earthquakes of a larger magnitude could result in major structural damage throughout the plant which would not be representative of a delta risk. The IEF of an earthquake in "Bin 2" was estimated to be 1.6E–5/yr for Byron using Table 4A–1 of Section 4 of the RASP handbook. To estimate the seismic capacity of the CW piping and the CW expansion joints, an evaluation of the seismic capacity for CW piping and expansion joints for another Westinghouse plant was referenced. For this plant, it stated that the CW piping and the CW expansion joints had high seismic capacity, and a flooding assessment due to seismic concerns was screened from the assessment. However, making the conservative assumption that the high confidence of low probability of failure capacity for the CW piping and the CW expansion joints was 0.3g, a failure probability of 3.9E–2 was obtained for the CW system.

Taking into account the exposure time of 3-months (0.25 years), and assuming that a Dual Unit LOOP with a failure of both EDGs would result in a core damage event, a bounding value for the delta ΔCDF for Case 2 is obtained as the product of the following factors:

Case 2: ΔCDF = [IEF] x [DLOOP] x [CW Failure Probability] x [Exposure Time]
= [1.6E–5/yr] x [1.0] x [3.9E–2] x [0.25]
= 1.6E–7/yr

A bounding ΔCDF of 1.6E–7/yr was estimated for seismically-induced flooding of the CW piping and CW expansion joints. The final ΔCDF associated with the finding is obtained as the sum of the delta CDF for both Case 1 and Case 2:

ΔCDF = [1.7E–7/yr] + [1.6E–7] = 3.3E–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. Byron Station is a 4-loop Westinghouse pressurized water reactor with a large dry containment. Sequences important to large early release frequency include 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 inspectors determined that the finding was of very low safety-significance (Green).

This finding has a cross-cutting aspect of Conservative Bias in the area of Human Performance because the licensee's decisions regarding disposition of the degraded condition did not indicate a conservative bias that emphasized prudent choices over those that were allowable. Even though mechanics identified the potential for the condition to degrade further in the near future, the work request was not given a high priority and continued functionality of the door was not evaluated through the next surveillance period by the licensee. (IMC 0310 H.14)

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented procedures of a type appropriate to the circumstances and be accomplished in accordance with these procedures.

Exelon Quality Assurance Topical Report, Chapter 1, "Organization," Section 2.4, identifies operability evaluations as a program element for implementing and/or reviewing areas of quality of plant operations and nuclear safety. The licensee established OP–AA–108–115, Revision 13, "Operability Determinations," as the implementing procedure for assessing the operability of SSCs and support functions for compliance with TSs when a degraded, nonconforming, or unanalyzed condition is identified, an activity affecting quality.

OP–AA–108–115, “Operability Determinations (CM–1),” identifies that SSCs not explicitly required to be operable by TS, but that perform required support functions for SSCs described in TS through the definition of operability are within the scope OP–AA–108–115. Step 4.1.20 of this procedure requires the functionality assessment of the SSC be performed and documented. This step is modified by a note that states in part, “For a functionality being performed for a non-TS SSC that supports an SSC described by TS, operability should be addressed in accordance with step 4.1.4 through step 4.1.9.” The referenced steps require performance and documentation of the operability determination of the affected SSC.

Contrary to the above, on March 25, 2014, Byron Station failed to implement the procedural requirements of OP–AA–108–115 for evaluating and documenting the operability of an SSC described by TS when a degraded condition of a supporting system was identified that could impact operability. Specifically, no operability determination was performed for the EDG fuel oil transfer pumps or the EDGs because the functionality assessment performed by the licensee failed to assess the potential for the condition to continue to degrade to the point that the door would become non-functional before the next surveillance was performed. When the degraded condition was not repaired in this instance, the door was found to be inoperable at the next surveillance making both Unit 2 EDGs inoperable.

Because this violation was of very low safety significance and it was entered into the licensee’s CAP, it is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000455/2014005–04, “Failure to Evaluate Operability of a TS SSC Upon Discovery of a Support System Degraded Condition”)**.

The licensee’s immediate corrective actions on June 25, 2014, included installing a temporary flood barrier on the doorway and documenting the issue in the CAP as IR 1675255. The water-tight door was repaired and returned to service on October 5, 2014.

1R19 <u>Post-Maintenance Testing</u> (71111.19)

a. <u>Inspection Scope</u>

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

- modification of the 2C condensate and condensate booster pump lube oil pressure switch;
- repair of the 2A and 2C reactor containment fan cooler chilled water inlet header check valve;
- replacement of the 0A essential service water make-up pump;
- planned maintenance on 1B auxiliary feedwater pump;
- repair of the safety injection actuation relay train A (SARA);
- replacement of the 2B auxiliary feedwater pump power take-off;
- testing of the thermal overloads on the emergency boration valve motor; and
- repair of the 2FW009C valve (2C steam generator feedwater inlet isolation valve).

These activities were selected based upon the SSC's ability to impact 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 TSs, 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 into the CAP at the appropriate threshold and correcting the problems 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 and contingency plans for the Unit 2 refueling outage conducted September 29–October 24, 2014, 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. Inspector's review of the Unit 2 shut down and initial outage activities was previously documented in Byron Station, Units 1 and 2 NRC Integrated Inspection Report 05000454(455)/2014004.

During the refueling outage, the inspectors monitored licensee controls over the outage activities listed below:

- 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;
- status and configuration of electrical systems and switchyard activities to ensure that TS and Outage Risk Management Profile requirements were met;

- 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 and sipping to detect fuel assembly leakage;
- 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 outage activities.

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

b. Findings

Introduction: Inspectors identified a finding of very low safety significance, Green, when the licensee impaired a flood protection boundary that supported a required safety function. Specifically, the licensee removed the flood barriers for auxiliary feedwater system containment isolation valves and rendered the valves inoperable prior to the plant reaching mode 5 and thereby entered TS 3.6.3 Condition C for operational convenience contrary to the TS Bases associated with TS 3.0.2 LCO Applicability.

Description: Technical Specification 3.6.3, "Containment Isolation Valves," requires containment isolation valves to be operable in Modes 1, 2, 3, and 4. On September 28, 2014, Byron Station Unit 2 began lowering power in preparation to take the unit off-line for refueling. At 08:10 PM, with Unit 2 still in Mode 1, the licensee declared the isolation valves inoperable and entered Condition C of that TS LCO. The operators then authorized mechanics to remove the flood barriers for auxiliary feedwater system tunnels which contain the containment isolation valves for the auxiliary feedwater system, 2AF013A through H. Technical Specification LCO 3.6.3 Condition C was exited at 05:36 AM on September 29 when Unit 2 entered Mode 5 and the LCO was no longer applicable.

The work to remove the flood seals was scheduled to occur from 10:00 PM on September 28 to 02:00 AM on September 29, 2014, but no work or other activities were planned to begin until later in the outage. The unit was scheduled to remain in Mode 1 until midnight (12:00 AM) on September 29 and transition to Mode 3 when the unit was shut down. The shutdown sequence moved the unit to Mode 4 at 3:53 AM on September 29 and Mode 5 at 05:36 AM.

While the flood barriers are required to support operability of the valves, risk evaluations performed for the period were not impacted during the activity because the isolation function was considered available under the procedures governing equipment availability.

Technical Specification LCO 3.0.2 bases states in part, “The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or the investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Alternatives that would not result in redundant equipment being inoperable should be used instead.”

Analysis: The inspectors determined that the licensee’s intentional entry into LCO 3.6.3.C was for operational convenience and constituted a performance deficiency. Specifically, the licensee intentionally rendered the auxiliary feedwater system containment isolation valves inoperable and relied on the LCO action requirements when they removed the flood barriers prior to the Unit being in a mode where the TS was not applicable. Since no maintenance or operating activity was required prior to Mode 5, removal of those barriers was performed solely for operational convenience to support the outage schedule and was contrary to the LCO 3.0.2 bases. This issue was entered into the licensee’s CAP as IR 2390265. Corrective actions included reviewing TS bases requirements with senior reactor operators and revising the schedule template to include logic ties for the activity to schedule it after Mode 5.

The inspectors evaluated the performance deficiency in accordance with IMC 0612 Appendix B, Issue Screening. This performance deficiency was not similar to any of the examples in IMC 0612 Appendix E, Examples of Minor Issues, issued August 11, 2009, but was characterized as more than minor because it impacted the SSC and Barrier Performance attribute of the Barrier Integrity Cornerstone; and adversely affected the cornerstone objective to provide reasonable assurance that the physical design barrier of the containment system protects the public from radionuclide releases caused by accidents or events. Specifically, the isolation function of containment was adversely impacted when isolation valves were made inoperable for operational convenience. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, Appendix A, “The Significance Determination Process For Findings At-Power,” Exhibit 3–Barrier Integrity Screening Questions, issued June 19, 2012, item B for the Reactor Containment. Both questions were answered "No" and therefore the finding screened as Green.

The inspectors determined that this finding had an associated cross-cutting aspect of Work Management in the Human Performance area because the shutdown and outage work schedules did not contain the rigor required to ensure the isolation valves were maintained operable as required by TS. (MC 0310 H.5)

Enforcement: Enforcement action does not apply because the performance deficiency did not involve a violation of regulatory requirements. Because this finding does not involve a violation and has very low safety significance, it is identified as a FIN **(FIN 05000455/2014005–05, Containment Penetration Isolation Valves Rendered Inoperable for Operational Convenience.)**

1R22 Surveillance Testing (71111.22)

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 XII–1; “Gaseous Leak Testing of the 2RH01SA/B Valve Containment Assemblies” (Routine);
- 2BOSR 6.1.1–21; “Unit Two Primary Containment Type C Local Leakage Rate Tests and IST (Inservice Test) Tests of Containment Chilled Water System” (Isolation Valve);
- 2BOSR 6.1.1–8; “Unit Two Primary Containment Type C Local Leakage Rate Tests and IST Tests of Primary Sampling System” (Isolation Valve);
- 2BVSR 6.1.1–26; “Unit 2 Primary Containment Type A Integrated Leakage Rate Test” (Routine); and
- 2BOSR 4.13.1–1; “Unit 2 Reactor Coolant System Water Inventory Balance Surveillance Computer Calculation” (RCS Leak Detection)

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 TS, 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;
- was test data and results accurate, complete, within limits, and valid;
- was test equipment removed following testing;
- where applicable for inservice testing activities, was testing performed in accordance with the applicable version of Section XI, ASME code, and were reference values consistent with the system design basis;
- was the unavailability of the tested equipment appropriately considered in the performance indicator 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, one reactor coolant system leak detection inspection sample, and two containment isolation valve samples as defined in IP 71111.22, Sections–02 and–05.

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System Evaluation (71114.02)

a. Inspection Scope

The inspectors reviewed documents and conducted discussions with Emergency Preparedness (EP) staff and management regarding the operation, maintenance, and periodic testing of the primary and backup Alert and Notification System (ANS) in Byron Station's plume pathway Emergency Planning Zone. The inspectors reviewed monthly trend reports and the daily and monthly operability records from January 2013 through July 2014. Information gathered during document reviews and interviews was used to determine whether the ANS equipment was maintained and tested in accordance with Emergency Plan commitments and procedures.

This ANS inspection constituted one sample as defined in IP 71114.02–06.

b. Findings

No findings were identified.

1EP3 Emergency Response Organization Staffing and Augmentation System (71114.03)

a. Inspection Scope

The inspectors reviewed and discussed with EP staff and management the Emergency Plan commitments and Emergency Response Organization (ERO) on-shift and augmentation staffing levels. A sample of 27 ERO training records for personnel assigned to key and support positions were reviewed to determine the status of their training as it related to their assigned ERO positions. The inspectors reviewed the ERO augmentation system and activation process, the primary and alternate methods of initiating ERO activation, unannounced off-hour augmentation tests from August 2012 through October 2014, and the provisions for maintaining the plant's ERO roster. The inspectors reviewed a sample of corrective actions related to the facility's ERO staffing and augmentation system program and activities from August 2012 through October 2014 to determine whether corrective actions were completed in accordance with the site's CAP.

This ERO augmentation testing inspection constituted one sample as defined in IP 71114.03–06.

b. Findings

No findings were identified.

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

a. Inspection Scope

The regional inspectors performed an in-office review of the latest revisions to the Emergency Plan, Emergency Plan Annex, and Emergency Plan Implementing Procedures as listed in the Attachment to this report.

The licensee transmitted the Emergency Plan and Emergency Action Level revisions to the NRC pursuant to the requirements of 10 CFR Part 50, Appendix E, Section V, "Implementing Procedures." The NRC review was not documented in a Safety Evaluation Report and did not constitute approval of licensee-generated changes; therefore, this revision is subject to future inspection. The specific documents reviewed during this inspection are listed in the Attachment to this report.

This Emergency Action Level and Emergency Plan Change Inspection constituted one sample as defined in IP 71114.04 06.

b. Findings

No findings were identified.

1EP5 Maintenance of Emergency Preparedness (71114.05)

a. Inspection Scope

The inspectors reviewed a sample of nuclear oversight staff's audits of the EP Program to determine whether these independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also reviewed critique reports and samples of CAP records associated with the 2013 Biennial Exercise, as well as various EP drills conducted in 2013 and 2014; in order to determine whether the licensee fulfilled drill commitments and to evaluate the licensee's efforts to identify, track, and resolve issues identified during these activities. The inspectors reviewed a sample of EP items and corrective actions related to the licensee's EP Program and activities to determine whether corrective actions were completed, in accordance with the site's CAP.

This correction of EP weaknesses and deficiencies inspection constituted one sample as defined in IP 71114.05–06.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

The inspection activities supplement those documented in Inspection Report 05000454(455)/2014002 and constitute one complete sample as defined in IP 71124.01–05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed all licensee performance indicators for the Occupational Exposure Cornerstone for follow-up. The inspectors reviewed the results of Radiation Protection Program audits (e.g., licensee's quality assurance audits or other independent audits). The inspectors reviewed any reports of operational occurrences related to occupational radiation safety since the last inspection. The inspectors reviewed the results of the audit and operational report reviews to gain insights into overall licensee performance.

b. Findings

No findings were identified.

.2 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors reviewed selected occurrences where a worker's electronic personal dosimeter noticeably malfunctioned or alarmed. The inspectors evaluated whether workers responded appropriately to the off-normal condition. The inspectors assessed whether the issue was included in the CAP and dose evaluations were conducted as appropriate.

b. Findings

No findings were identified.

.3 Contamination and Radioactive Material Control (02.04)

a. Inspection Scope

The inspectors reviewed the licensee's criteria for the survey and release of potentially contaminated material. The inspectors evaluated whether there was guidance on how to respond to an alarm that indicates the presence of licensed radioactive material.

The inspectors reviewed the licensee's procedures and records to verify that the radiation detection instrumentation was used at its typical sensitivity level based on appropriate counting parameters. The inspectors assessed whether or not the licensee has established a *de facto* "release limit" by altering the instrument's typical sensitivity through such methods as raising the energy discriminator level or locating the instrument in a high-radiation background area.

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 evaluated whether any transactions, since the last inspection, involving nationally tracked sources were reported in accordance with 10 CFR 20.2207.

b. Findings

No findings were identified.

.4 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

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.

The inspectors examined the licensee's physical and programmatic controls for highly activated or contaminated materials (i.e., nonfuel) stored within spent fuel and other storage pools. The inspectors assessed whether appropriate controls (i.e., administrative and physical controls) were in place to preclude inadvertent removal of these materials from the pool.

The inspectors examined the posting and physical controls for selected high radiation areas and very-high radiation areas to verify conformance with the occupational performance indicator.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors discussed with the radiation protection manager the controls and procedures for high-risk, high radiation areas and very-high radiation areas. The inspectors discussed methods employed by the licensee to provide stricter control of very-high radiation area access as specified in 10 CFR 20.1602, "Control of Access to Very-High Radiation Areas," and Regulatory Guide 8.38, "Control of Access to High and Very-High Radiation Areas of Nuclear Plants." The inspectors assessed whether any changes to licensee procedures substantially reduce the effectiveness and level of worker protection.

The inspectors discussed the controls in place for special areas that have the potential to become very high radiation areas during certain plant operations with first-line health physics supervisors (or equivalent positions having backshift health physics oversight authority). The inspectors assessed whether these plant operations require communication beforehand with the health physics group, so as to allow corresponding timely actions to properly post, control, and monitor the radiation hazards including re-access authorization.

The inspectors evaluated licensee controls for very-high radiation areas and areas with the potential to become very-high radiation areas to ensure that an individual was not able to gain unauthorized access to the very-high radiation areas.

b. Findings

No findings were identified.

.6 Radiation Worker Performance (02.07)

a. Inspection Scope

The inspectors reviewed radiological problem reports since the last inspection that found the cause of the event to be human performance errors. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. The inspectors discussed with the radiation protection manager any problems with the corrective actions planned or taken.

b. Findings

No findings were identified.

.7 Radiation Protection Technician Proficiency (02.08)

a. Inspection Scope

The inspectors reviewed radiological problem reports since the last inspection that found the cause of the event to be radiation protection technician error. The inspectors evaluated whether there was an observable pattern traceable to a similar cause. The inspectors assessed whether this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

b. Findings

No findings were identified.

.8 Problem Identification and Resolution (02.09)

a. Inspection Scope

The inspectors evaluated whether problems associated with radiation monitoring and exposure control were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involve radiation monitoring and exposure controls. The inspectors assessed the licensee's process for applying operating experience to their plant.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index-Emergency Alternating Current Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI)-Emergency Alternating Current Power System Performance Indicator (PI) (MS06) for Byron Station Units 1 and 2 for the period from the fourth quarter 2013 through the third quarter 2014. To determine the accuracy of the PI 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, was used. The inspectors reviewed the licensee's operator narrative logs, MSPI derivation reports, IRs, event reports and NRC Integrated Inspection Reports for the period of October 2013 through September 2014 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted two MSPI emergency AC power system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index-High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI-High Pressure Injection Systems PI (MS07) for Byron Station Units 1 and 2 for the period from the fourth quarter 2013 through the third quarter 2014. To determine the accuracy of the PI 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 narrative logs, MSPI derivation reports, IRs, event reports and NRC Integrated Inspection Reports for the period of October 2013 through September 2014 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted two MSPI high pressure injection system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index-Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI-Heat Removal System PI (MS08) for Byron Station Units 1 and 2 for the period from the fourth quarter 2013 through the third quarter 2014. To determine the accuracy of the PI 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 narrative logs, MSPI derivation reports, IRs, event reports and NRC Integrated Inspection Reports for the period of October 2013 through September 2014 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted two MSPI heat removal system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.4 Mitigating Systems Performance Index-Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI-Residual Heat Removal System PI (MS09) for Byron Station Units 1 and 2 for the period from the fourth quarter 2013 through the third quarter 2014. To determine the accuracy of the PI 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 narrative logs, MSPI derivation reports, IRs, event reports and NRC Integrated Inspection Reports for the period of October 2013 through September 2014 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted two MSPI residual heat removal system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.5 Mitigating Systems Performance Index-Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI-Cooling Water Systems PI (MS10) for Byron Station Units 1 and 2 for the period from the fourth quarter 2013 through the third quarter 2014. To determine the accuracy of the PI 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 narrative logs, MSPI derivation reports, IRs, event reports and NRC Integrated Inspection Reports for the period of October 2013 through September 2014 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted two MSPI cooling water system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.6 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the Occupational Exposure Control Effectiveness PI (OR01) for the period from the third quarter 2013 through the third quarter 2014. The inspectors used guidance contained in NEI 99–02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, dated August 2013, to determine the accuracy of the Performance Indicator data reported during those periods. The inspectors reviewed the licensee’s assessment of the PI for occupational radiation safety to determine if the indicator related data was adequately assessed and reported. The inspectors discussed with radiation protection staff the scope and breadth of its data review and the results of those reviews; to assess the adequacy of the licensee’s PI data collection and analyses. The inspectors independently reviewed electronic personal dosimetry dose rate and accumulated dose alarms and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted walkdowns of numerous locked high and very-high radiation area entrances to determine the adequacy of the controls in place for these areas.

This inspection constituted one occupational exposure control effectiveness sample as defined in IP 71151–05.

b. Findings

No findings were identified.

.7 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors sampled licensee submittals for the Reactor Coolant System Specific Activity PI (BI01) for Byron Station Units 1 and 2 for the period from the third quarter 2013 through the third quarter 2014. The inspectors used guidance contained in NEI 99–02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, dated August 2013, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee’s reactor coolant system chemistry samples, TS requirements, IRs, event reports and NRC Integrated Inspection Reports to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s CAP to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. In addition to record reviews, the inspectors observed a chemistry technician obtain and analyze a reactor coolant system sample.

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

b. Findings

No findings were identified.

.8 Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors sampled licensee submittals for the Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences PI (PR01) for the period from the third quarter 2013 through the fourth quarter 2014. The inspectors used guidance contained in NEI 99–02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, dated August 2013, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee’s CAP and selected individual reports generated since this indicator was last reviewed to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous effluent summary data and the results of associated offsite dose calculations for selected dates to determine if indicator results were accurately reported. The inspectors also reviewed the licensee’s methods for quantifying gaseous and liquid effluents, and determining effluent dose.

This inspection constituted one Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences sample as defined in IP 71151 05.

b. Findings

No findings were identified.

.9 Drill/Exercise Performance

a. Inspection Scope

The inspectors sampled licensee submittals for the Drill/Exercise Performance PI (EP01) for the period from the fourth quarter 2013 through the second quarter 2014. Guidance contained in NEI 99–02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, was used to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee’s records and processes associated with the PI to verify the licensee accurately reported the DEP indicator in accordance with licensee procedures and NEI guidance. Specifically, the inspectors reviewed licensee records, processes, and procedural guidance for assessing opportunities, including control room simulator training sessions, the 2013 Biennial Exercise, and other drills during this period. The inspectors also reviewed the licensee’s CAP to determine if problems had been identified and corrected.

This inspection constitutes one DEP sample as defined in IP 71151–05.

b. Findings

No findings were identified.

.10 Emergency Response Organization Drill Participation

a. Inspection Scope

The inspectors sampled licensee submittals for the ERO Drill Participation PI (EP02) for the period from the fourth quarter 2013 through the second quarter 2014. The inspectors used guidance contained in NEI 99–02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, dated August 2013, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee’s records associated with the PI to verify that the licensee accurately reported the indicator in accordance with relevant procedures and NEI guidance. Specifically, the inspectors reviewed licensee records and processes, including procedural guidance on assessing opportunities for the PI, performance during the 2013 Biennial Exercise, drills, and revisions of the roster of personnel assigned to key ERO positions. The inspectors also reviewed the licensee’s CAP to determine if problems had been identified and corrected.

This inspection constitutes one ERO drill participation sample as defined in IP 71151–05.

b. Findings

No findings were identified.

.11 Alert and Notification System Reliability

a. Inspection Scope

The inspectors sampled licensee submittals for the ANS PI (EP03) for the period from the fourth quarter 2013 through the second quarter 2014. The inspectors used guidance contained in the NEI 99–02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, dated August 2013, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee’s records associated with the PI to verify that the licensee accurately reported the indicator in accordance with relevant procedures and NEI guidance. Specifically, the inspectors reviewed licensee records and processes for assessing opportunities for the PI and results of periodic ANS operability tests. The inspectors also reviewed the licensee’s CAP to determine whether the problems had been identified and corrected.

This inspection constitutes one ANS sample as defined in IP 71151–05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

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

.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. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment to this report.

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 IR 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 June 1, 2014, through November 30, 2014, although some examples expanded beyond those dates where the scope of the trend warranted.

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

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

b. Findings

No findings were identified.

.4 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Minutes from the operator workarounds (OWA) committee meetings were reviewed to verify the licensee was meeting the station procedural requirements and were considering the appropriate deficiencies when determining operator challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the OWAs on system availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents.

The inspectors reviewed both current and historical operational challenge records to determine whether the licensee was identifying operator challenges at an appropriate threshold, had entered them into their CAP, and proposed or implemented appropriate and timely corrective actions which addressed each issue. Reviews were conducted to determine if any operator challenge could increase the possibility of an Initiating Event, if the challenge was contrary to training, required a change from long-standing operational practices, or created the potential for inappropriate compensatory actions. Additionally, all temporary modifications were reviewed to identify any potential effect on the functionality of Mitigating Systems, impaired access to equipment, or required equipment uses for which the equipment was not designed. Daily plant and equipment status logs, degraded equipment logs, and operator aids or tools being used to compensate for material deficiencies were also assessed to identify any potential sources of unidentified operator workarounds. Electronic searches of the CAP documentation were also performed to identify timeliness of corrective actions for any chronic or long term equipment issues identified in other reviews.

This review constituted one operator workaround annual inspection sample as defined in IP 71152–05.

b. Findings

No findings were identified.

.5 Selected Issue Follow Up Inspection: Corrective Actions Unit 2 Stuck Reactor Vessel Stud No. 11

a. Inspection Scope

On October 1, 2014, the licensee applied specialized vendor tooling and removed the Unit 2 stuck reactor vessel stud at location No. 11, which had been abandoned in place since May of 2002. Following stud removal, the inspectors observed the licensee performing a visual examination with the aid of a boroscope, to determine the condition of the stud threads and cavity below the stud No. 11. The licensee identified and removed loose corrosion products and debris with the aid of a vacuum and then used a special cleaning tool to remove adherent corrosion/boric acid products fixed to the bottom of the flange stud hole. Samples of the adherent corrosion product debris were obtained by the licensee for analysis. The analysis results determined that in excess of 1000 ppm boron was present in this debris indicating that borated water had been present under the abandon head stud. The licensee documented the corrosion and debris at this stud hole No. 11 location in IR 02389646. The inspectors assessed the following attributes during review of the licensee corrective actions associated with this issue:

- 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/reportability issues;
- classification and prioritization of the resolution of the problem, commensurate with safety significance;
- identification of the apparent and/or contributing causes of the problem; and
- identification of corrective actions, which were appropriately focused to correct the problem.

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

b. Findings

No findings were identified.

.6 Selected Issue Follow-Up Inspection: Failure to Implement Compensatory Actions Per Plant Barrier Impairment Authorization When Flood Barrier Removed For SX pump Work.

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized an IR documenting failure of plant staff to implement compensatory actions before they impaired a flood barrier. Issue Report 2406628 documented that operations staff authorized removal of the floor plug forming the flood barrier without verifying that the compensatory actions required by Plant Barrier Impairment Permit (PBI) 14–334 were complete. The barrier was impaired for 20 hours before the operators recognized that the compensatory actions had not been verified. The PBI specified two compensatory actions: (1) close the discharge valve for the affected pump; and (2) close the applicable valve pit floor drain. The inspectors determined that the discharge valve had been closed for pump maintenance prior to the plug removal so this action had been completed prior to barrier impairment.

The valve pit floor drain had not been previously closed, but was closed when the omission was discovered. The hazard to be mitigated in this condition is flooding on the 346 foot elevation of the auxiliary building that would fill the valve pit, drain into the floor drain system and back up into the pump room after sump pump failure. The inspector reviewed the flooding analysis and piping/room drawings and while this scenario is possible it is not considered likely to occur. The second compensatory action is a prudent action, but would not impact the essential service water pumps.

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

b. Findings

The performance deficiency and enforcement aspects of this issue are discussed in Section 4AO7.2 of this report.

.7 Selected Issue Follow-Up Inspection: Inoperable Fire Door Due To Bent Astragal On Double Door.

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting an inoperable fire door due to a partially detached and bent astragal on the door. Issue Report 2398582 documented that on October 22, 2014, the astragal on a double door, which is designated as a fire door, was bent out from the door allowing an open area between the stationary door and the active door. This gap caused the fire door to be declared inoperable in accordance with Technical Requirement Manual 3.10.g, and an hourly fire watch was instituted until the astragal was repaired. The inspectors identified that there were five IRs documented in a 3-month span involving the astragal on this fire door. The first three of these IRs did not identify the deficient astragal to be impairment to the fire barrier, and one was documented 2-days before the door was declared inoperable. These IRs were all closed to work orders and no compensatory actions were taken. After the door was declared inoperable on October 22, 2014, maintenance attempted to repair the door, but the astragal became detached and bent again, so another IR was documented, and a modification was made to the door to prevent further damage to the astragal.

After further review by the inspectors and the licensee, the licensee determined that the decision to call the fire door inoperable on October 22, 2014, was a conservative decision, and that the deficient astragal did not actually render the fire door inoperable. Therefore, no compensatory measures were required.

While the operability of the fire door was not impacted by the degraded astragal, the inspectors identified that the documented functional basis for two of the CAP documents

(IRs 2390927 and 2398582) did not contain the detail prescribed in OP–AA–108–115, "Operability Determinations (CM–1)," as they did not describe the effect of the degraded condition on the SSC's ability to perform its specified function. The inspectors reviewed this performance deficiency using the criteria contained in NRC IMC 0612, Appendix B, "Issue Screening," and determined the issue was not more than minor.

The inspectors reviewed the logs and work orders related to this door, as well as the surveillance procedure and acceptance criteria for the door. The inspectors assessed the following attributes during review of the licensee corrective actions associated with this issue:

- complete, accurate, and timely documentation of the identified problem in the corrective action program;
- evaluation and timely disposition of operability and reportability issues;
- consideration of extent of condition and cause, generic implications, common cause, and previous occurrences;
- completion of corrective actions in a timely manner commensurate with the safety significance of the issue; and,
- action taken results in the correction of the identified problem.

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

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

.1 (Closed) Licensee Event Report 05000454/2014–002: Non-Compliance with Technical Specification 3.4.3, "RCS [Reactor Coolant System] Pressure and Temperature Limits"

Byron Station reported this issue on April 10, 2014, after receiving a Pressurized Water Reactor Owner's Group letter discussing an operation at another power plant impacting RCS pressure using vacuum filling operations. TS 3.4.3 LCO is applicable at all times and states, "RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR (Pressure Temperature Limits Report.) At Byron, the PTLR contains the curves that depict the operating limits and is contained in the technical requirements manual. The lower bound of these curves was zero pounds per square inch gauge (0 psig). Byron staff recognized that the site had been using a vacuum fill operation to fill RCS piping since 2011 using Byron procedure BOP RC–9 which provides instructions for using vacuum to fill RCS piping in Mode 5 and would allow pressure as low as 28.5 inches of mercury or a pressure of about negative 14 psig.

After review, the inspectors concluded that this condition did not represent a violation of the TS LCO, but did represent a condition outside of the parameters used in the analysis used by Westinghouse to generate the PTLR curves. Westinghouse performed the additional analysis needed to expand the lower value of the curves and revised the PTLR at the licensee's request. The revised curves for Unit 1 and Unit 2 were electronically submitted to the NRC on March 27, 2014, under Byron transmittal letter BYRON 2014–0040.

The enforcement aspects of this event are discussed in Section 4OA7.1 of this report. This LER is closed.

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

.2 <u>(Closed) Licensee Event Report 05000455/2014–004–00; Byron Unit 2 Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzle Weld Indication Attributed to Primary Water Stress Corrosion Cracking</u>

On October 7, 2014, an indication was discovered on Unit 2 Head Penetration No. 6. The indication was located on the outside diameter of the penetration tube and the deepest wall depth was 0.222 inches, approximately 34.11 percent through wall.

The indication was subsequently repaired using the embedded flaw technique in accordance with NRC approved WCAP–15987, Revision 2–A and WCAP–16401, Revision 0. The apparent cause of the indication is attributed to Primary Water Stress Corrosion Cracking. Corrective actions including repair of the indication on Penetration No. 6 and revision of the inspection frequency of the Unit 2 volumetric examinations on all 78 reactor pressure vessel penetrations to every refueling outage. Inspectors observed repair activities and considered the actions taken to be appropriate. Additional information regarding these repair activities was included in Section 1R08 of this report. This LER is closed.

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

4OA5 <u>Other Activities</u>

.1 <u>(Closed) Unresolved Item 05000454/2012008–02, 05000455/2012008–02, “Operability Determination Procedure Implementation Concerns”</u>

As documented in NRC Special Inspection Team (SIT) Report 05000455/2012008, inspectors identified a concern related to the implementation of procedure OP–AA–108–115, “Operability Determinations (CM–1),” Revision 11. Specifically, the inspectors questioned whether OP–AA–108–115 was properly implemented since an operability determination was not performed upon discovery of the design vulnerability that was the subject of the inspection.

The special inspection reviewed the circumstances surrounding the January 30, 2012, electrical insulator failure in the Byron switchyard that resulted in a Unit 2 automatic reactor trip and Notice of Unusual Event emergency declaration. The licensee identified that the insulator failure resulted in a loss of a single phase on the offsite supply line to Unit 2 and resulted in a degraded voltage condition that did not automatically disconnect the safety busses and start the emergency diesel generators. Operators took manual actions to open the offsite supply breaker, creating the bus undervoltage condition and the diesels automatically transferred to energize the busses. The licensee entered the issue into the CAP as IR 1319908 and declared the offsite line inoperable.

Following the prompt review of the event sequence, the licensee initiated IR 1322212 documenting the design vulnerability and providing an operability evaluation of the SSCs covered by TS 3.3.5, “Loss of Power Diesel Generator Start Instrumentation,” based on engineering judgment. The operators then assigned an action to engineering to provide a more detailed technical basis for operability (i.e., an Operability Evaluation). The licensee concluded that because the undervoltage protection system functioned as designed, and because the NRC had reviewed and approved the design, the requirements of TS 3.3.5 were met and the identified design vulnerability in the undervoltage/degraded voltage protection scheme did not impact operability of the undervoltage/degraded voltage protection. This decision was based largely on the licensee's position that the event was outside of their CLB or beyond the design basis. The completed Operability Evaluation supported the original engineering judgment conclusion. The question regarding whether the undervoltage and degraded voltage protection design vulnerability met the requirements of general design criteria 17 and was therefore within the station's CLB is currently under review by NRR and is being tracked by unresolved item (URI) 05000454/2012008–001, 05000455/2012008–001; "Inadequate Undervoltage Protection."

The inspectors were concerned with the licensee's conclusion that the undervoltage and degraded voltage protection systems remained operable since it appeared that the design would not adequately mitigate a loss of "A" or "C" phase event in the absence of operator action, which appeared to not satisfy the intent of the undervoltage and degraded voltage protection systems to ensure that engineered safety feature (ESF) Busses 241 and 242 were powered from either offsite power or automatically transferred to the DGs. The inspectors identified an URI related to the implementation of operability determination procedure OP–AA–108–115. Specifically, the inspectors questioned whether OP–AA–108–115 was properly implemented since an operability determination for the undervoltage and degraded voltage protection circuits was not performed upon discovery that the undervoltage protection scheme did not disconnect the ESF busses from the grid following a loss of a single phase. The special inspection team provided specific insights into weaknesses in OP–AA–108–115 during the inspection. The Inspector's review of Revision 13 of that procedure indicated that all of the team's comments on the procedure weaknesses have since been corrected.

Inspectors have determined that the operability determinations were conducted in accordance with Revision 11 of the procedure and that the licensee's conclusions regarding the station's understanding of the licensing basis were included in those determinations and supporting documents. Inspector identified weaknesses in OP–AA–108–115 have been corrected. No findings were identified. This URI is closed.

.2 <u>(Closed) Unresolved Item 05000454/2012008–03, 05000455/2012008–03, Potential Missed Opportunities to Identify a Latent Undervoltage Design Issue</u>

As documented in NRC SIT Report 05000455/2012008, inspectors identified a concern related to potential missed opportunities to identify the ESF undervoltage protection design vulnerability through the use of operating experience. The licensee entered the unresolved item into the CAP as IR 1327770 and asked the corporate operating experience group to answer a series of questions concerning the operating experience review conducted for other insulator issues that have occurred in the industry. Examples of past single phase failures were reviewed to determine if the design vulnerability should have been identified before this event in January 2012. Issue Reports 1325488 and 1327246 documented additional operating experience reviews performed. The licensee concluded that the initial reviews were correct in their evaluation that Byron had already implemented the actions recommended by the applicable operating experience and in fact had a more robust program looking for switchyard deficiencies than that recommended by the operating experience documents. One issue identified by the licensee review is that the operating experience did not drive the industry as a whole to review single phase protection schemes. Instead, the operating experience documents focused on monitoring and identifying the failure rather than ensuring that the protection scheme was robust enough to identify the failure and activate protective relays. The licensee reviews also concluded that design vulnerabilities beyond the component level defect were not considered credible since a single phase failure was concluded to be beyond design bases.

After discussion with NRC regional management, inspectors determined that URI 05000454/2012008–001, 05000455/2012008–001; "Inadequate Undervoltage Protection," is sufficient to track resolution of the overall issue as the design compliance with GDC–17 and the Byron licensing bases remain under review by NRR. The licensee implemented additional challenge reviews of operating experience reviews performed at the station and implemented a modification that added protective relays to detect an open single phase condition on the offsite power feed and automatically trip the offsite power feed to the ESF buses on a single open-phase signal. This URI is closed.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 6, 2015, the inspectors presented the inspection results to Mr. R. Kearney 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 exits were conducted for:

- the inspection results of the inservice inspection with Mr. R. Kearney, Site Vice President, on October 10, 2014.
- the inspection results for the areas of radiological hazard assessment and exposure controls; and occupational exposure control effectiveness performance indicator verification with Mr. R. Kearney on October 10, 2014;
- the inspection results of the EP area inspections with Mr. R. Kearney conducted at the site on October 24, 2014;
- inspection observations during annual operating test with Mr. M. McCue, Operations Training Manager, and other members of the licensee staff on November 5, 2014;
- the annual review of Emergency Action Level and Emergency Plan Changes with the licensee's emergency preparedness coordinator, Mr. R. Lloyd, via telephone on December 3, 2014; and
- overall pass/fail results of the biennial written examination and annual operating test via telephone between T. Sanders, LORT Lead, and M. Bielby, Senior Operations Inspector, on December 15, 2014.

The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

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 an NCV.

1. On February 1, 2014, the licensee identified that vacuum pressures were used to fill RCS piping multiple times since 1998 resulting in RCS system pressures below 0 psig and entered the issue into the CAP process as IR 1625960. Byron TS 3.4.3, “RCS Pressure and Temperature Limits,” states “RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR (Pressure Temperature Limits Report.) The PTLR is generated by Westinghouse and contains graphs depicting the acceptable operating ranges of RCS pressure and temperature supported by analysis. The lower bound of these graphs was 0 psig. Byron procedure BOP RC–9, “Filling an Isolated Reactor Coolant Loop, The Pressurizer, and Drawing a Pressurizer Bubble,” was used by the station to fill the loops. This procedure allowed RCS piping pressure to go as low as 28 inches of mercury (approximately–14 psig) which is outside the lower bound of the PTLR acceptable region. Procedural controls for the upper bounding limits were appropriate. At the licensee’s request, Westinghouse performed the additional analysis needed to expand the lower value of the curves and determined that the lower bounding parameter could be changed to–14.7 psig with no impact to the RCS barriers. The analysis was subsequently revised and the PTLR revised to designate the lower boundary accordingly. 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality be prescribed by procedures appropriate to the circumstances. Contrary to the above, between April 1998 and October 2013, BOP RC–9 allowed RCS pressures to be lower than the analyzed lower bound of the parameter inputs of the PTLR graphs and thus was not appropriate to the circumstances. The finding was more than minor because it had the potential to adversely impact the Procedure Quality attribute of the Reactor Safety–Barrier Integrity Cornerstone objective to provide reasonable assurance that the RCS design barrier would function to protect the public from radionuclide release caused by accidents or events. Given the analytical conclusion that the condition was acceptable with the new lower bounding parameter, the inspectors determined that there was no change in risk with the issue and the finding was screened as Green.

2. On November 4, 2014, the licensee identified that the floor plug forming the internal flood barrier to an essential service water pump valve pit in the auxiliary building was removed prior to completion of the compensatory actions required by the Plant Barrier Impairment Permit, PBI 14–334. 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality be prescribed by procedures appropriate to the circumstances. Plant Barrier Control Program, CC–AA–201, assigns responsibility to Operations Management in step 4.4.2 to “ensure compensatory actions are in place prior to authorizing ‘permission to impair’ the barrier.” In step 6.5.2.1 of CC–AA–201, Operations Management is required to “ensure compensatory actions are in place” prior to authorizing the impairment of the barrier. Contrary to the above, the licensee operating staff allowed impairment of the barrier without implementing the procedurally required compensatory actions. The licensee entered the issue in the CAP process as IR 2406628 and immediately implemented the compensatory

actions on discovery of the omission. Inspectors determined that this issue was more than minor because the performance deficiency adversely impacted the Mitigating Systems Cornerstone objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences in that intentional impairment of a design barrier is a modification that adversely impacts the attribute of design control and must be performed in accordance with approved procedures and processes. The inspector's evaluation of the missed actions determined that the affected systems would perform their credited functions and using IMC 0609, Appendix A, “The Significance Determination Process For Findings At-Power,” Exhibit 2, Mitigating Systems Screening Questions, Question A.1, determined that the finding screened as Green.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

R. Kearney, Site Vice President
T. Chalmers, Plant Manager
G. Armstrong, Security Manager
B. Barton, Radiation Protection Manager
T. Cain, Acting Nuclear Oversight Manager
R. Kartheiser, Emergency Preparedness Coordinator
C. Keller, Engineering Director
R. Lloyd, Emergency Preparedness Manager
K. Moss, Nuclear Oversight Assessor
D. Spitzer, Regulatory Assurance Manager
L. Zurawski, NRC Coordinator
M. McCue, Operations Training Manager
G. Contrady, Regulatory Assurance
J. Fiesel, Maintenance Director
E. Hernandez, Operations Director
S. Kerr, Training Director
B. Peters, Shift Operations Superintendent
L. Sanders, LORT Lead and Exam Author
F. Paslaski, Rad Engineering Manager
M. Yousuf, Programs Engineering Supervisor
R. McBride, Programs Engineer

Nuclear Regulatory Commission

J. Ellegood, Acting Chief, Reactor Projects Branch 3
D. E. Hills, Chief, Reactor Safety Branch 1

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000454/2014005–01; 05000455/2014005–01	NCV	Failure to Measure Interpass Temperature (Section 1R08.1.b.1)
05000454/2014005–02; 05000455/2014005–02	NCV	Liquid Penetrant Testing Procedure Did Not Meet ASME Code (Section 1R08.1.b.2)
05000454/2014005–03; 05000455/2014005–03	NCV	Welding Procedure Specification Variables Changed Without Revision or Amendment Contrary to ASME Code (Section 1R08.1.b.3)
05000455/2014005–04	NCV	Failure to Evaluate Operability of a TS SSC Upon Discovery of a Support System Degraded Condition (Section 1R15)
05000455/2014005–05	FIN	Containment Penetration Isolation Valves Rendered Inoperable for Operational Convenience (Section 1R20)

Closed

05000454/2014005–01; 05000455/2014005–01	NCV	Failure to Measure Interpass Temperature (Section 1R08.1.b.1)
05000454/2014005–02; 05000455/2014005–02	NCV	Liquid Penetrant Testing Procedure Did Not Meet ASME Code (Section 1R08.1.b.2)
05000454/2014005–03; 05000455/2014005–03	NCV	Welding Procedure Specification Variables Changed Without Revision or Amendment Contrary to ASME Code (Section 1R08.1.b.3)
05000455/2014005–04	NCV	Failure to Evaluate Operability of a TS SSC Upon Discovery of a Support System Degraded Condition (Section 1R15)
05000455/2014005–05	FIN	Containment Penetration Isolation Valves Rendered Inoperable for Operational Convenience (Section 1R20)
05000454/2014–002–00	LER	Non-compliance with Technical Specification 3.4.3, “RCS Pressure and Temperature Limits” (Section 4OA3)
05000455/2014–004–00	LER	Byron Unit 2 Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzle Weld Indication Attributed to Primary Water Stress Corrosion Cracking (Section 4OA3)
05000454/2012008–02, 05000455/2012008–02	URI	Operability Determination Procedure Implementation Concerns (Section 4OA5)
05000454/2012008–03, 05000455/2012008–03	URI	Potential Missed Opportunities to Identify a Latent Undervoltage Design Issue (Section 4OA5)

Discussed

05000454/2012008–001 05000455/2012008–001	URI	Inadequate Undervoltage Protection (Section 4OA5)

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.

Section 1R01

- IR 2400815; Local Intense Precipitation (LIP) FLO-2d Modeling Issues
- ENERCON Report for Byron Station Flood Hazard Re-evaluation dated March 12, 2014
- 0BOSR XFT-A5, Revision 10; Freezing temperature Equipment Protection Non-Protected Area Buildings
- BOP XFT-1, Revision 6; Cold Weather Operations
- M-42, Sheet 6; Revision BC; Diagram of Essential Service Water
- BAR 0VH01J-1-B5, Revision 1; River Screen House Temperature Low
- BAR 0-34-E8, Revision 54; Common HVAC Local Pnl Trouble
- Analysts, Inc. Laboratory Report: Diesel Fuel; December 19, 2014

Section 1R04

- M-37, Revision BD; Diagram of Auxiliary Feedwater
- M-138, Sheet 3A; Revision AW; Diagram of Chemical and Volume Control and Boron Thermal Regeneration
- M-152, Sheet 9; Revision AA; Manufacturer's Supplemental Diagram of Diesel Generator Lube Oil Schematic
- M-152, Sheet 10; Revision AD; Manufacturer's Supplemental Diagram of Diesel Generator Fuel Oil Schematic
- M-152, Sheet 18; Revision R; Diagram of Starting Air

Section 1R05

- Pre-Fire Plan FZ 9.1-2, FZ 9.4-2; Revision 1; Auxiliary Building 2B Diesel Generator & Day Tank Room – 401'-0" Elevation
- Pre-Fire Plan FZ 11.2B-2; Revision 0; Auxiliary Building 346'-0" Elevation 2A Containment Spray Pump Room
- Pre-Fire Plan FZ 11.2A-2; Revision 0; Auxiliary Building 346'-0" Elevation 2A RHR Pump Room
- Pre-Fire Plan FZ 11.2C-2; Revision 0; Auxiliary Building 346'-0" Elevation 2B Containment Spray Pump Room
- Pre-Fire Plan FZ 11.2D-2; Revision 0; Auxiliary Building 346'-0" Elevation 2A RHR Pump Room

Section 1R08

- AR 01430775; Recordable Indications Discovered During ISI Examination; April 17, 2013
- AR 01501702; Seismic Support 2SI01014X (Loose Bolting, Angularity OOT); April 14, 2013
- AR 01507959; Mode 3 W/D Dry B/B Leak on 2CV8117; April 29, 2013
- AR 01503278; Recordable Indications Discovered During ISI Examination; May 17, 2013
- AR 01508214; Body-to-Bonnet Leak on 2CV131; April 30, 2013
- AR 01613143; 2BR7006 Leaking; January 27, 2014

- AR 01635115; Inactive Boric Acid on Flange Upstream of 2SI01PA; March 18, 2014
- AR 01672990; Boric Acid on Flange Bolting Upstream of 2SI121A; June 19, 2014
- AR 01694034; NOS ID, Finding Restraint not in ISI Plan; August 19, 2014
- AR 02393595; NRC ID, Issues with Vendor Exam Procedure; October 10, 2014
- AR 02392483; NRC-ID, Vendor Welding Guideline Document for Kerotest Vlv; October 8, 2014
- AR 02392248; UT Indication in CRDM Penetration 6 B2R18M5; October 7, 2014
- AR 02391463; 2SI15004X (Recordable Ind. ID'd During ASME IWF Exam); October 6, 2014
- AR 01676939; SX Piping Wall Thinning Acceptance Criteria Error; June 30, 2014
- AR 02395440; NOS QV ID'd Preheat of Base Material Not Performed; October 14, 2014
- 80165; Curtiss Wright, Liquid Penetrant Inspection Procedure; Revision X, November 20, 2003
- VTIP F-2354.001; Welding Guidelines for Welding Small Valves into System Piping, GTAW – Process
- WDI-PJF-1313102-FSR-001; Byron Generating Station Outage – B1R18 Reactor Vessel Head Penetration Examination – Preliminary NDE Report Summary: Revision 0
- MA-MW-796-101; Welding, Brazing and Soldering Records; Revision 5
- M-919; Component Support Installation Guidelines and Tolerances; Revision J
- ER-AA-335-016; VT-3 Visual Examination of Component Supports, Attachments and Interiors of Reactor Vessels; Revision 9
- Report No. B2R17-UT-022; UT of 2RC-01-BA/SGC-08; April 18, 2013
- WO 01505231; Scheduled NDE of Class 1, 2, and 3 Components; April 18, 2013
- WO 01025526; Hot Leg Check Valve Leak-By Indication; February 26, 2013, 2013
- WO 01323963; 2C NDE of the Reactor Coolant Pump Flywheels; January 31, 2013
- WO 01478575; Minor Leakage from Seal Weld on 2SI8819A; October 10, 2012
- WDI-STD-1040; Wesdyne Procedure for Ultrasonic Examination of Reactor Vessel Head Penetrations; Revision 11
- WDI-STD-1041; Wesdyne Procedure for Reactor Vessel Head Penetration Ultrasonic Examination Analysis; Revision 10
- PDQS; WDI-STD-1041 Revision 3; dated March 2, 2010
- PDQS; WDI-STD-1040 Revision 5; dated March 4, 2010
- WO 01480596; Replace Kerotest Check Valve 2SI8900C; February 26, 2013
- WPS 1-1-GTSM-PWHT; WPS for Manual GTAW/SMAW P1 to P1 Material; Revision 2
- PQR A-001; PQR for WPS 1-2RC1-GTSM-PWHT; October 19, 1998
- PQR A-002; PQR for WPS 1-1-GTSM-PWHT; March 9, 1999
- PQR 1-50C; PQR for WPS 1-1-GTSM-PWHT; January 3, 1984
- WPS 8-8GTSM; WPS for Manual GTAW/SMAW P1 to P1 Material; Revision 3
- PQR 1-51A; PQR for WPS WPS 8-8GTSM; December 28, 1983
- PQR 4-51A; PQR for WPS WPS 8-8GTSM; September 12, 1986
- PQR A-003; PQR for WPS WPS 8-8GTSM; February 8, 2000
- PQR A-004; PQR for WPS WPS 8-8GTSM; February 8, 2000

Section 1R11

- Cycle 14-6 Evaluated Scenario
- OP-AA-101-111-1001; Operations Standards and Expectations; Revision 14
- OP-AA-102-106; Operator Response Time Program; Revision 3
- OP-AA-105-101; Administrative Process for NRC License and Medical Requirements; Revision 15
- OP-AA-105-102; NRC Active License Maintenance; Revisions 9, 10, and 11
- OP-BY-101-0004; Strategies for Successful Transient Mitigation; Revision 6
- OP-BY-102-106; Operator Response Time Program at Byron Station; Revision 5

- TQ-AA-150; Operator Training Programs; Revision 10
- TQ-AA-155; Conduct of Simulator Training and Evaluations; Revision 3
- TQ-AA-201; Examination Security and Administration; Revision 16
- TQ-AA-203; On the Job Training and Job Performance Evaluation; Revision 9
- TQ-AA-306; Simulator Management; Revision 7
- TQ-AA-306; Byron Simulator Core Model Evaluation for U-1 Cycle 20, Attachment 9, Pressurized Water Reactor Core Performance Testing; March 28, 2014
- TQ-AA-306; Byron Simulator Core Model Evaluation for U-1 Cycle 20, Attachment 10, MTC of Reactivity; November 18, 2013
- TQ-AA-306; Byron Simulator Core Model Evaluation for U-1 Cycle 20, Attachment 11, Rod Worth Coefficient of Reactivity; March 28, 2014
- TQ-AA-306; Byron Simulator Core Model Evaluation for U-1 Cycle 20, Attachment 12, Boron Coefficient of Reactivity; November 19, 2013
- TQ-AA-306; Byron Simulator Core Model Evaluation for U-1 Cycle 20, Attachment 13; Xenon Worth; November 18, 2013
- TQ-AA-306; Byron Simulator Core Model Evaluation for U-1 Cycle 20, Attachment 16, Approach to Criticality Using Boric Acid; March 28, 2014
- TQ-AA-306; Byron Simulator Core Model Evaluation for U-1 Cycle 20, Attachment 17, Approach to Criticality Using Control Rods; November 18, 2013
- Byron Simulator Steady State Test; Lower Power Level; SS-1; Revision 2; June 30, 2014
- Byron Simulator Steady State Test; Mid-Range Power Level; SS-2; Revision 2; June 30, 2014
- Byron Simulator Steady State Test; Full Power Level; SS-3; Revision 2; June 30, 2014
- Byron Simulator Malfunction Test; Real Time Test; RT01; August 29, 2014
- Byron Simulator Transient Test; Manual Reactor Trip; TR-1; Revision 6; June 20, 2014
- Byron Simulator Transient Test; Simultaneous Trip of All Main Feedwater Pumps; TR-2; Revision 7; June 20, 2014
- Byron Simulator Transient Test; Simultaneous Closure of All Main Steam Isolation Valves; TR-3; Revision 6; June 20, 2014
- Byron Simulator Transient Test; Simultaneous Trip of All Reactor Coolant Pumps; TR-4; Revision 6; June 20, 2014
- Byron Simulator Transient Test; Trip of Any Single Reactor Coolant Pump; TR-5; Revision 6; June 20, 2014
- Byron Simulator Transient Test; Turbine Trip (Maximum Power Level Which Does Not Result in Immediate Reactor Trip; TR-6; Revision 6; June 20, 2014
- Byron Simulator Transient Test; Maximum Rate Power Ramp; TR-7; Revision 6; June 20, 2014
- Byron Simulator Transient Test; Maximum Size Reactor Coolant System Rupture Combined with a Loss of All Offsite Power; TR-8; Revision 6; June 20, 2014
- Byron Simulator Transient Test; Maximum Size Unisolable Main Steam Line Rupture; TR-9; Revision 6; June 20, 2014
- Byron Simulator Transient Test; Slow Primary System Depressurization to Saturated Condition Using Pressurizer Relief Stuck open (Inhibited Actuation of Centrifugal Charging Pumps); TR-10; Revision 6; June 20, 2014
- Byron Simulator Transient Test; Maximum Design Load Reduction; TR-11; Revision 6; June 20, 2014
- IR1472593; TRGN-Crew Did Not Meet TCA [Time Critical Action] Time Required; February 7, 2013
- IR1506862; SFP [Spent Fuel Pool] Level Reduced; April 26, 2013
- IR1519964; 2B and 2D RCFC Fans OLR [Online Risk] Not Communicated; May 31, 2013
- IR1521443; TRGN-Crew Failed Simulator OBE [Out of the Box Evaluation]; June 4, 2013

- IR1533360; Operations Deep Dive – OP Key Gap 3; July 8, 2013
- IR1567369; PI&R 2A DG Operability Concern; September 26, 2013
- IR1650818; Unexpected Alarm in MCR/1B DG Inoperable; April 23, 2014
- IR1652425; 4.0 Critique for 1B DG Inoperability; April 24, 2014
- IR1660105; TRGN-LORT Cycle 14-3 Failed DEP [Drill and Exercise Performance] Classification; May 14, 2014
- Byron Simulator and Plant Differences Report; Revision 2; November 19, 2014
- List of Open Simulator Work Requests; dated November 24, 2014
- List of Closed Simulator Work Requests; dated November 24, 2014
- 2014 Pre-71111.11 Inspection Focused Area Self-Assessment; June 25, 2014
- 2014 Week 1 LORT Comprehensive Written Exam
- 2012 Week 5 LORT Comprehensive Written Exam
- 2014 Week 1; Scenario BY-58; Revision 6
- 2014 Week 1; Scenario BY-73; Revision 6
- 2014 Week 3; Scenario BY-61; Revision 6
- 2014 Week 3; Scenario BY-81; Revision 4
- 2014 Week 5; Scenario BY-78; Revision 5
- 2014 Week 5; Scenario BY-84; Revision 2
- Six JPMs from 2014 Week 1 of the Requalification Exams
- Six JPMs from 2014 Week 5 of the Requalification Exams

<u>Section 1R12</u>

- Maintenance Rule Summary for Function VC (Auxiliary Building HVAC)
- Maintenance Rule Summary for Function WS (Non-essential Service Water)
- Maintenance Rule Summary for Function SX-05 (UHS temperature control)
- IR 2403010; Maintenance Rule Unavailability Criterion Exceeded for 0SX162D
- IR 2405733; 0SX162B Exceeded Its Maintenance Rule Unavailability Limit
- System engineer evaluation and (a)(1) determination for Maintenance Rule Function SX-05

<u>Section 1R13</u>

- Work Week 10/6/2014 Online Risk Evaluation; Revisions 2, 3 & 4
- OU-AP-104; Revision 20
- IR 2392112; On Line Risk PRA Model Enhancement Identified
- IR 2391804; Lost DC Bus 212 Due to Crosstie Breaker Tripping Open
- 2BOA Elec-1; Revision 102; Loss of DC Bus Unit 2
- BY-Mode-009; Revision 2; TS 3.0.4.b Evaluation – Modes 3, 2and 1, Entry with 2PR11J, 2PC104M, and 2MS018B Inoperable
- Work Week December 29, 2014 Online Risk Evaluation; Revisions 2 & 3
- UFSAR Section 8.2.1; Offsite (Preferred) Power System

<u>Section 1R15</u>

- EC 351042; Evaluation Acceptability of Flexible Hoses on 2CV22MA, 2CV29MA, 2CV30MA, 2CV29MB, and 2CV30MB
- IR 2390770; Static Bend Radius is Less than Minimum Criteria
- IR 2390771; Static Bend Radius is Less than Minimum Criteria
- ECR 415215; Attempt to Remove Reactor Closure Stud #11
- WO 01643464; Install Reactor Vessel Head Per BMP 3118-7
- IR 2389646; Corrosion Found in Unit 2 Reactor Head Studhole 11

- IR 2392782; Abnormal Condition of 212 Battery Cells
- IR 2392789; Negative Plates on 212 Battery Bent
- EC 399715; Revision 0; Evaluation for the Acceptance of 212 ESF Batteries with Positive Plate Misalignment and Bent Negative Plates
- Letter from Larry A. Carson of C&D Technologies, Inc. dated October 10, 2014; "LCUN-33 Cells with Misalignment Issues"
- IR 2407921; Missed Surveillance: 18-Month NIs Unit 1 Power Range ½ Trip
- BY-SURV-007; Revision 0; Risk Assessment Missed Surveillance – 1BOSR 3.1.7-41, 1BOSR 3.1.7-42, 1BOSR 3.1.7-43, and 1BOSR 3.1.7-44
- IR 2416985; Issue With Specific Gravity Results
- IEEE Standard 450-1995; Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications; January 24, 1995
- MA-BY-721-06;, Revision 15; 125 Volt Battery Bank Quarterly Surveillance
- TS 3.8.6, Battery Parameters, and Associated Bases

<u>Section 1R19</u>

- IR 2395421; 2WO007A Failed As Left Leak Rate (Second Time)
- M-118, Sheet 7, Revision AC; Diagram of Containment Chilled Water System
- WO 1632740; RCFC Cooling Coils Chilled Water Inlet Header Check Valve
- WO 1649351; LLRT for P-6 and P-10 – 2WO006A/B, 2WO007A/B
- EC 398037, Revision 1; Modify Logic for Unit 2 Condensate and Condensate Booster Pumps Lube Oil Pressure Switches
- WO 1736197; Modify Logic for 2C CD/CB Pump Switches EC 398037
- ECR 414894; Requesting Engineering Support for Testing Criteria for Allen Bradley Type "C" Control Relay
- IR 2396753; Higher than Expected Resistance on Closed Contacts
- 2BOSR 6.1.1-21, Revision 10; Unit Two Primary Containment Type C Local Leakage Rate Tests and IST Tests of Containment Chilled Water System
- WO 1779268; 2FW009C Pump Running Every 7 Minutes
- WO 1713570; Rebuild 0A SX M/U Pump
- ER-AA-321, Revision 12; Administrative Requirements for Inservice Testing
- IR 2407973; 0A SX Makeup Pump Was Operating Outside of Acceptable Range
- WO 1761167; 0SX02PA Comprehensive IST Req for SX Makeup Pump
- WO 1776068; 0A SX Makeup Pump Operability Surv
- 0BOSR 5.5.8.SX.5-1c, Revision 7; Unit Zero Comprehensive Inservice Testing (IST) Requirements for Essential Service Water Makeup Pump 0A
- WO 1578924; Check Alignment / Inspect / Replace Coupling
- WO 1604659; Test/Replace MCCB's
- WO 1520274; Test/Replace MCCB's on 1B Dsl Drv AF Pp 1A Batt Chgr
- 1BOSR 5.5.8.AF.5-2a, Revision 6; Unit One Group A Inservice Testing (IST) Requirements for Diesel Driven Auxiliary Feedwater Pump 1AF01PB
- IR 2388711; SARA Sequencer Failed Testing – B2R18M4
- IR 2390820; Damaged Relay Contact Blocks on "SARA" Relay in 2PA13J
- IR 2390255; 2BOSR EF-1 Still Failed After Repair Attempt – B2R18M4
- IR 2390492; 2A Train SARA Relay Failure
- WO 1773616; SARA Sequencer Failed Testing – B2R18M4
- 2BOSR ER-1, Revision 5; Train A – SARA and ESF Sequencer Testing – 2PA13J

Section 1R20

- IR 2390534; 2A SG Secondary Manway Cover Seating Surface Anomaly
- IR 2390908; B2R18 Bus 242 Clearance Order Issue
- IR 2390926; 2SXA9A-6" UT Identified Areas Below Min. Wall Requirements
- IR 2396149; NRC Identified Issues During Containment Walkdown
- IR 2396833; NRC ID, Boric Acid Leak from 2FE-0418
- IR 2390265; NRC ID, AF [Auxiliary Feed] Tunnel Flood Seals Open Prior to Mode 5
- TS LCO 3.6.3; Containment Isolation Valves
- TS LCO 3.0.2 (failure to meet an LCO) and Associated Basis
- BY-MODE-009, Revision 2; TS 3.0.4.b Evaluation – Modes 3, 2 and 1 Entry with 2PR11J, 2PC104M, and 2MS018B Inoperable
- LS-AA-119-1001; Revision 3; Fatigue Management
- IR 2392194; Siemens for Cause Fatigue Assessment
- IR 2391809; Fatigue Assessment for IR 2391726
- Clearance Order (CO) 118593; SI Line Flex Mod EC 393365
- CO 118727; SI Pp Suction – Install Flex Mod Per 393365
- IR 2392100; NRC ID, Dry Fitting Leakage – 2FIS-0448B
- IR 2387756; NRC ID, Dry Boric Acid Deposits
- 2BGP 100-5; Revision 58; Plant Shutdown and Cooldown

Section 1R22

- 2BOSR XII-1; Revision 1; Gaseous Leak Testing of the 2RH01SA/B Valve Containment Assemblies
- WO 1683365; Perform Leakage Test
- IR 1480456; Potential NUREG0737 Program Deficiency (1/2RH01SA/B)
- M-136, Sheet 4; Revision AZ; Diagram of Safety Injection
- 2BOSR 4.13.1-1, Revision 30; Unit Two Reactor Coolant System Water Inventory Surveillance Computer Calculation
- WO 1637637; LLRT for P-5 and P-8 – 2WO056A/B, 2WO020A/B, and 2WO079A/B
- WO 1649351; LLRT for P-6 and P-10 – 2WO006A/B, 2WO007A/B
- 2BOSR 6.1.1-21, Revision 10; Unit Two Primary Containment Type C Local Leakage Rate Tests and IST Tests of Containment Chilled Water System
- WO 1632051; LLRT for P-70 – 2PS9354A and 2PS9354B
- M-140, Sheet 1; Revision AQ; Diagram of Process Sampling (Primary & Secondary)
- WO 1632050; LLRT for P-70 – 2PS9357A and 2PS9357B
- 2BOSR 6.1.1-8; Revision 11; Unit Two Primary Containment Type C Local Leakage Rate Tests and IST Tests of Primary Sampling System
- 2BVSR 6.1.1-26; Revision 8; Unit 2 Primary Containment Type A Integrated Leakage Rate Test (ILRT)
- IR 2397833; Flow Indicated into Reactor Cavity (Incore) Sump During B2R18
- IR 2397910; RCDT Level Increase During ILRT
- BVP 800-39; Revision 11; Byron Containment Leakage Rate Testing Program

Section 1EP2

- Offsite Emergency Plan Alert and Notification System Addendum for Byron Station; August 2009
- U. S. Department of Homeland Security, FEMA Letter; Backup Alert and Notification System; December 10, 2012

- EP-AA-1000; Exelon Nuclear Standardized Radiological Emergency Plan Section E; Revision 25
- EP-AA-1002; Exelon Nuclear Radiological Emergency Plan Annex for Byron Station, Section 4; Revision 33
- PI-AA-126-1001-F-01; Focused Area Self-Assessment-ANS; September 24, 2014
- Byron Station Warning System Annual Maintenance & Operational Reports; May - August 2014
- Byron Station Monthly Siren Availability Reports; January 2013 – July 2014
- Byron Semi-Annual Siren Reports; January 2013 - June 2014
- IR 1677552; Siren Failures Due to Weather Related Loss of Power; July 1, 2014

Section 1EP3

- EP-AA-1000; Exelon Nuclear Standardized Radiological Emergency Plan, Sections B and N; Revision 25
- EP-AA-1002; Exelon Nuclear Radiological Emergency Plan Annex for Byron Station, Section 2; Revision 33
- EP-AA-1002; Exelon Nuclear Radiological Emergency Plan Annex for Byron Station, Addendum 1, On-Shift Staffing Technical Basis; Revision 0
- TQ-AA-113; ERO Training and Qualification; Revision 23
- Quarterly Unannounced Off-Hours Call-In Augmentation Drill Results; August 2012 – October 2014
- Emergency Response Organization Call-Out Roster; September 29, 2014
- IR 2119423; ACE-September 8 Drive In Drill OSC Did Not Meet Minimum Augmentation Staffing In Required Time; October 2, 2014
- IR 1618395; Quarterly Call-In Drill Failure; February 7, 2014
- IR 1670721; Two ERO Duty ERO Team Members Did Not Respond to Call-In Drill; June 12, 2014
- IR 1628153; Inadvertent Activation of Byron ERO Pagers; March 1, 2014
- IR 1527459; ERO Duty Environs Monitoring Team Member Did Not Respond to Call-In Drill; June 21, 2013
- IR 1465323; ERO Duty OSC Director Did Not Respond to Call-In Drill; January 22, 2013
- IR 1406146; ERO Duty Team Member Did Not Respond to Call-In Drill; August 28, 2012

Section 1EP4

- EP-AA-1000; Exelon Nuclear Standardized Radiological Emergency Plan; Revisions 24 and 25
- EP-AA-1002; Radiological Emergency Plan Annex for Byron Station; Revisions 32 and 33
- EP-AA-110-200; Dose Assessment; Revisions 4, 5, 6, and 7
- EP-AA-110-200-F-01; Dose Assessment Input Form; Revision B
- EP-AA-110-201-F-01; On-Shift Dose Assessment Input Sheet; Revision B
- EP-AA-112-100-F-02; Shift Dose Assessor; Revision F

Section 1EP5

- EP-AA-1000; Exelon Nuclear Standardized Radiological Emergency Plan Section D.3, Timely Classification of Events-Hostile Action; Revision 25
- EP-AA-1000; Exelon Nuclear Standardized Radiological Emergency Plan Section J, Protective Response; Revision 25

- EP-AA-1002; Exelon Nuclear Radiological Emergency Plan Annex for Byron Station, Section 3,Classification of Emergencies; Revision 33
- EP-AA-1002; Exelon Nuclear Radiological Emergency Plan Annex for Byron Station, Section 5.1, Emergency Response Facilities; Revision 33
- EP-AA-1002; Exelon Nuclear Radiological Emergency Plan Annex for Byron Station, Addendum 2, Evacuation Time Estimates for Byron Station Emergency Planning Zone; Revision 0
- EP-MW-124-1001-F-14; Monthly NARS Communications Test; October 20, 2014
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- EP-AA-121; Emergency Response Facilities and Equipment Readiness; Revision 12
- EP-AA-121-F-02; Byron Equipment Matrix; Revision 2
- EP-AA-120-1001; 10 CFR 50.54(q) Change Evaluation; Revision 7
- EP-AA-1002, Addendum 2; Evacuation Time Estimates for the Byron Station; Revision 1
- LS-AA-126-1005; Check-In Self-Assessment; September 18, 2014
- PI-AA-125; Corrective Action Program (CAP) Procedure; Revision 0
- PI-AA-126-1001-F-01; Focused Area Self-Assessment-NRC Pre-Inspection; September 25, 2014
- NOSA-BYR-14-03; Emergency Preparedness Audit Report; April 9, 2014
- NOSA-BYR-13-03; Emergency Preparedness Audit Report; April 10, 2013
- EP Information #2012; Byron Station Moves to New EP Offsite Staging Area; June 2012
- Byron 2014 off-Year Exercise Evaluation Report; June 17, 2014
- Biennial Letters of Agreement; February – March 2014
- Plan of the Day EP EITER List; October 2014
- Operator Aid 2010-0004; List of Inaudible Public Address System Locations; October 22, 2014
- IR 2384610; Reschedule 18 ERO Members For Annual Requalification Training; September 22, 2014
- IR 1681931; Off Year Exercise TSC Failed Demonstration Criteria; July 15, 2014
- IR 1643233; NOS Identified Mechanical Maintenance Less Than 50% Respiratory Qualifications; April 4, 2014
- IR 1570488; Pre-Exercise Objective Failures For Dose Assessment and KI; dated October 10, 2013
- IR 1562015;Loss of Phone Communications; September 21 2013
- IR 1462311; Public Address System Priorities and Operator Aid Deficiencies; January 14, 2014

<u>Section 2RS1</u>

- IR 1595809; Non-Conservative Decision Making; dated November 26, 2013
- IR 1631930; Improper Egress and Ingress from a High Radiation Area; dated March 10, 2014
- IR 1501175; High Radiation Area Identified during Radiological Surveys; dated April 12, 2013
- IR 1584070; Primary to Secondary Dose Discrepancy; dated November 12, 2013
- IR 1489557; Over-Responding Neutron EDs; dated March 19, 2013
- IR 1552699; Sealed Source No. 856 Found Degraded; dated August 30, 2013
- IR 1639346; NOS ID: Incorrect Source Used for ARGOS-5 Daily Checks; dated March 27, 2014
- RP-AA-503; Unconditional Release Survey Method; Revision 8
- RP-AA-460; Controls for High and Locked High Radiation Areas; Revision 26
- RP-AA-460-002; Additional High Radiation Exposure Control; Revision 2
- RP-AA-460-003; Access to HRAs/LHRAs/VHRAs and Contaminated Areas in Response to a Potential or Actual Emergency; Revision 7
- Semi-Annual Source Inventory; File Location 2.12.2200.55; dated July 8, 2014

- Semi-Annual Source Leak Test; File Location 2.12.2200.58; dated July 8, 2014

<u>Section 4OA1</u>

- LS-AA-2140; Attachment 1; Monthly Data Elements for NRC Occupational Exposure Control Effectiveness; July 2013 through September 2014
- LS-AA-2090; Monthly Data Elements for NRC Reactor Coolant System (RCS) Specific Activity; July 2013 through September 2014
- CY-AA-130-3010; Dose Equivalent Iodine Determination; Revision 4
- LS-AA-2150; Monthly Data Elements for RETS/ODCM Radiological Effluent Occurrences; July 2013 through September 2014
- LS-AA-2110; Monthly Data Elements for NRC ERO Drill Participation; December 2013 - June 2014
- LS-AA-2120; Monthly Data Elements for NRC Drill/Exercise Performance; October 2013 - June 2014
- LS-AA-2130; Monthly Data Elements for NRC Alert and Notification System Reliability; October 2013 - June 2014
- Byron ANS Test Reports; October 2013 - June 2014
- Industry Quarterly EP Performance Indicator Results; First Quarter 2013 – Second Quarter 2014
- IR 1689782; Performance Indicator Historical Data Revision Second Quarter 2014; August 6, 2014
- IR 1660105; LORT Training Failed DEP Classification; May 14, 2014
- IR 1618501; LORT Training Failed DEP Classification; February 7, 2014
- IR 1607567; Public Address System Speaker Correction; January 13, 2014
- BY-MSPI-001, Revision 16; Reactor Oversight Program MSPI Basis Document – Byron Nuclear Generating Station
- LS-AA-2200, Revision 5; Mitigating System Performance Index Data Acquisition & Reporting;
- MSPI Monthly Data Elements for Emergency AC Power System (DG); October 2013 – September 2014
- MSPI Monthly Data Elements for High Pressure Injection Systems (CV & SI); October 2013 – September 2014
- MSPI Monthly Data Elements for Heat Removal Systems (AF); October 2013 – September 2014
- MSPI Monthly Data Elements for Residual Heat Removal Systems (RH); October 2013 – September 2014
- MSPI Monthly Data Elements for Cooling Water Systems (CC); October 2013 – September 2014
- NEI 99-02, Revision 7; Regulatory Assessment Performance Indicator Guideline
- IR 1633538; 1RH8702B Failed to Reopen During 1BOSR 5.5.8.RH.3-2 (R2)

<u>Section 4OA2</u>

- ECR 415215; Attempt to Remove Reactor Closure Stud #11
- WO 01643464; Install Reactor Vessel Head Per BMP 3118-7
- IR 2389646; Corrosion Found in Unit 2 Reactor Head Studhole 11
- IR 2391113; RPV Stud Hole #11 Needs Threads to Be Polished
- Byron Degraded Equipment Log dated October 29, 2014
- Quarterly Presentation of Operations Concerns; Plant Health Committee Minutes dated 9/15/2014
- Open Operability Evaluations and Associated Compensatory Actions as of October 29, 2014

- IR 2420020; Quarterly Work-Around Meeting Missed
- Operator Work-Around Board Meeting Minutes dated May 19, 2014
- Operator Work-Around Board Meeting Minutes dated December 5, 2014
- BAP 1100-3A3; Revision 37; Plant Barrier Control Program
- BAP 1100-3A3; Revision 38; Plant Barrier Control Program
- PBI No. 14-334; Barrier Impairment Authorization and Compensatory Action Tracking Form for Work Order 1587172EC 393060, Revise Auxiliary Building Flooding Calculation Zones G1-1A and G1-1B
- EC 400024; Revision 0; Revise Flood Calculation 3CB-1281-001
- EC 399883; Revision 1; Impact of Potential Flood on SX Pump Room with Flood Seal Open
- S&L Evaluation 2014-09017; Revision 0; Essential Service Water Pump Flooding
- IR 2406628; Issue With PBI 14-334
- IR 1694897; Astrigal Bent and Not Fastened to Door at Bottom
- IR 2390927; Metal Flashing Bent and Missing Screws
- IR 2397718; 0DSD725 Not Closing and Latching
- IR 2398582; Metal Door Strip Protruding 4-5 Inches; Personnel Safety Haz
- IR 2399230; 0DSD725 Fire Door Inoperable
- IR 2400560; 0DSD725 Fire Door Inoperable
- PBI No. 14-399; Barrier Impairment Permit for Degraded Door Latch Mechanism Preventing Door from Closing and latching
- 0BMSR 3.10.g.4, Revision 21; Fire Door Semi-Annual Inspection
- EC 339805; Fire Door Acceptance Criteria
- NFPA 252, 2012 Edition; Standard Methods of Fire Tests of Door Assemblies
- OP-MW-201-007, Revision 7; Fire Protection System Impairment Control

<u>Section 4OA3</u>

- IR 1625960; Potential To Exceed RCS PTLR Limits During Vacuum Fill
- BOP RC-9; Filling an Isolated Reactor Coolant Loop, the Pressurizer, and Drawing a Pressurizer Bubble
- LER 454-2014-002-00; Non-compliance with Technical Specification 3.4.3, “RCS Pressure and Temperature Limits”

<u>Section 4OA5</u>

- ML12087A213; Byron Unit 2 – NRC Special Inspection team (SIT) Report 05000455/2012008
- OP-AA-108-115, Revision 11; Operability Determinations (CM-1)
- OP-AA-108-115, Revision 13; Operability Determinations (CM-1)
- IR 1319908; B2F26 Unit 2 Reactor Trip Due to Electrical Fault and Unusual Event
- IR 1322212; B2F26 Potential Design Vulnerability in Switchyard Single Open Phase
- EC 387590, Revisions 001 through 008; Op Eval 12-001 – Potential Design Vulnerability in Switchyard Single Open Phase Detection
- IR 1325902; Gaps in Guidance of Op Determination Procedure
- IR 1327246; Byron Station Review of OE26134
- IR 1325488; OE26134 Applicability Review
- IR 1327770; Missed Opportunity for Reviewing OPEX
- IR 2392644; NRC ID: Scaffold Leg Resting on Unistrut Floor Plate
- IR 2393725; Trickle Charge Light Extinguished on 2LL049E / App R Inop
- IR 2395282; 0DSSD194 All Watertight Dog Legs Not Fully Engaged – NRC Iden

Section 4OA7

- BAP 1100-3A3; Revision 37; Plant Barrier Control Program
- BAP 1100-3A3; Revision 38; Plant Barrier Control Program
- PBI No. 14-334 (Barrier impairment Authorization and Compensatory Action Tracking Form for Work Order 1587172EC 393060, Revise Auxiliary Building Flooding Calculation Zones G1-1A and G1-1B
- EC 400024; Revision 0; Revise Flood Calculation 3CB-1281-001
- EC 399883; Revision 1; Impact of Potential Flood on SX Pump Room with Flood Seal Open
- S&L Evaluation 2014-09017; Revision 0; Essential Service Water Pump Flooding
- CC-AA-201; Revision 10; Plant Barrier Control Program
- BAP 1100-3; Revision 23; Plant Barrier Impairment (PBI) Program
- IR 2406628; Issue With PBI 14-334

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
ANS	Alert and Notification System
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CDF	Core Damage Frequency
CLB	Current Licensing Bases
CFR	Code of Federal Regulations
CW	Circulating Water
DLOOP	Dual Unit Loss of Offsite Power
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
EPRI	Electric Power Research Institute
ERO	Emergency Response Organization
ESF	Engineered Safety Feature
ET	Eddy Current Test
FLEX	Diverse and Flexible Coping Strategies
GTAW	Gas Tungsten Arc Welding
IEF	Initiating Event Frequency
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report
ISI	Inservice Inspection
IST	Inservice Test
JPM	Job Performance Measure
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOOP	Loss of Off-site Power
LORT	Licensed Operator Requalification Training
MSPI	Mitigating Systems Performance Index
MT	Magnetic Particle Test
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OWA	Operator Workaround
PARS	Publicly Available Records System
PBI	Plant Barrier Impairment
PI	Performance Indicator
PIM	Plant Issues Matrix
PPR	Plant Performance Review
psig	Pounds Per Square Inch Gauge
PT	Liquid Penetrant Test
PTLR	Pressure Temperature Limits Report
RASP	Risk Assessment Standardization Project
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RH	Residual Heat
SAPHIRE	Systems Analysis Program for Hands-on Integrate Reliability Evaluations
SAT	Systematic Approach to Training

SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection
SIT	Special Inspection Team
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SSC	System, Structure and/or Component
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VTIP	Vendor Technical Information
WPS	Welding Procedure Specification
WO	Work Order

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Sincerely,

/RA/

John Ellegood, Acting Chief
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