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

April 28, 2015

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

SUBJECT: BYRON STATION, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000454/2015001; 05000455/2015001

Dear Mr. Hanson:

On March 31, 2015, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Byron Station, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on April 16, 2015, with the Byron Plant Manager, Mr. T. Chalmers, and other members of your staff. The inspectors documented the results of this inspection in the enclosed inspection report.

Based on the results of this inspection, one NRC-identified finding of very low safety significance was identified. The finding involved a violation of NRC requirements. In addition, an issue that was determined to be a Severity Level IV violation using the traditional enforcement process was also identified. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the violations as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy. A licensee-identified violation which was determined to be of very low safety significance is also documented in Section 4OA7 this report.

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

Eric R. Duncan, Chief
Branch 3
Division of Reactor Projects

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

Enclosure:
IR 05000454/2015001; 05000455/2015001
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000454; 05000455
License Nos:	NPF–37; NPF–66
Report No:	05000454/2015001; 05000455/2015001
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	Byron, IL
Dates:	January 1 through March 31, 2015
Inspectors:	J. McGhee, Senior Resident Inspector J. Draper, Resident Inspector C. Thompson, Resident Inspector, Illinois Emergency Management Agency
Approved by:	E. Duncan, Chief Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

Inspection Report 05000454/2015001, 05000455/2015001; 01/01/2015–03/31/2015; Byron Station, Units 1 and 2; Identification and Resolution of Problems

This report covers a 3-month period of inspection by the resident inspectors. The inspectors identified one Green finding and one Severity Level IV violation. The finding and Severity Level IV violation 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" dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas" dated January 1, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated February 4, 2015. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process" Revision 5, dated February 2014.

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 V, "Instructions, Procedures, and Drawings," when licensee personnel failed to provide work instructions appropriate to the circumstances for a work activity affecting quality. In particular, the licensee's work instructions for modifying Unit 2 safety-related relays failed to include guidance on foreign material exclusion issues identified previously during a similar Unit 1 modification. This resulted in foreign material preventing Unit 2 Safeguards Actuation Relay Train 'A' from actuating during surveillance testing. The licensee subsequently replaced the affected relay prior to declaring the system operable, performed an extent of condition review on similar relays on both Units 1 and 2, and entered the issue into their Corrective Action Program (CAP) as Issue Report (IR) 2388711.

The performance deficiency was more than minor because it was associated with the Procedure Quality attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the reliability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The Senior Reactor Analysts (SRAs) performed a detailed risk analysis and concluded that the finding was of very low safety significance. The finding had a cross-cutting aspect in the Evaluation component of the Problem Identification and Resolution cross-cutting area because the licensee failed to thoroughly evaluate the foreign material identified on Unit 1 to ensure that the resolution addressed the extent of condition. (P.2) [Section 4OA2.3]

Cornerstone: Emergency Preparedness

Severity Level IV. The inspectors identified a Severity Level IV NCV of 10 CFR 50.72(b)(3)(xiii) when licensee personnel failed to notify the NRC of a major loss of emergency assessment capability within 8 hours of the failure of the onsite seismic monitor used to classify an emergency action level. Upon recognizing that the event was reportable, the licensee made the notification to the NRC and entered the issue into their CAP as IR 2464734.

The inspectors determined that this issue had the potential to impact the regulatory process based, in part, on the generic communications input that 10 CFR 50.72 reports serve. Since the issue impacted the regulatory process, it was dispositioned through the traditional enforcement process. The inspectors determined that this issue was a Severity Level IV violation based on Section 6.9, “Inaccurate and Incomplete Information or Failure to Make a Required Report,” Example d.9 in the NRC Enforcement Policy. Example d.9 specifically stated, “A licensee fails to make a report required by 10 CFR 50.72 or 10 CFR 50.73.” Because a more-than-minor Reactor Oversight Process finding was not identified, there was no cross-cutting aspect associated with this violation. [Section 4OA2.4]

Licensee-Identified Violations

A violation of very low safety significance that was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee’s CAP. This violation and associated CAP tracking number 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 February 27, 2015, when power was lowered to 82 percent to support maintenance on the Unit 2 system auxiliary transformers (SAT 242–1 and SAT 242–2) and associated switchyard buses. The unit was restored to full power on March 2, 2015, and operated at full power until March 3, 2015, when an electrical fault on the 1E main power transformer caused a turbine trip and reactor trip. The unit remained shut down in Mode 3 during the repair and testing of the main power transformer. The reactor was restarted on March 8, 2015, and the generator was synchronized to the grid on March 9, 2015. The unit returned to full power on March 10, 2015. Additional discussion of this reactor trip is included in Section 4OA3.1 of this report.

On March 27, 2015, reactor power was reduced to 64 percent to support continued maintenance on the Unit 2 SATs and associated buses. The unit was restored to full power on March 29, 2015.

Unit 2

The unit began the period at full power and operated at or near full power for the entire inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate Alternating Current Power Systems

a. Inspection Scope

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

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

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

- actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply;
- compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;
- re-assessment of plant risk based on maintenance activities which could affect grid reliability, or the ability of the transmission system to provide offsite power; and
- communications between the plant and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

On March 3, 2015, the inspectors observed the licensee and TSO implement these procedural requirements following a trip of Unit 1 concurrent with an out-of-service SAT 242–2. The licensee declared the affected offsite line inoperable in accordance with plant technical specifications (TSs) and implemented previously identified compensatory actions. The operating shift then coordinated with the TSO to raise grid voltage to restore voltage above post-trip required levels. 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.

This inspection constituted one readiness of offsite and alternate AC power systems 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 design basis probable maximum flood and local intense precipitation (LIP). The evaluation included a review to check for deviations from the descriptions provided in the updated final safety analysis report (UFSAR) for features intended to mitigate the potential for flooding from external factors. 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 a probable maximum precipitation event or allow water ingress past a barrier. The inspectors also reviewed the abnormal operating procedure for mitigating the design basis flood and LIP to ensure mitigating actions assumed in design calculations were included and the procedure could be implemented as written.

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:

- Unit 2 component cooling water (CC) system with common unit CC heat exchanger aligned to Unit 2 during the heat exchanger work window;
- 1A residual heat removal (RHR) train after inservice testing program surveillance run; and
- 1B diesel generator (DG) during 1A DG maintenance activities.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors determined whether any discrepancies existed that could impact the function of the system and therefore potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, the UFSAR, TS requirements, outstanding work orders (WOs), 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 that impacted the safety function. 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 March 18, 2015, the inspectors performed a complete system alignment inspection of the Unit 1 safety injection system to verify the functional capability of the system. This system was selected because it was considered both safety-significant and risk-significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups, electrical power availability, instrumentation, component labeling, component lubrication, component and equipment cooling, pipe hangers and supports, and the operability of support systems. In addition, plant housekeeping was reviewed to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of outstanding maintenance WOs and design changes was performed to determine whether any deficiencies significantly affected the system function. The inspectors also reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved.

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

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- 1A Safety Injection Pump Room;
- 1A Centrifugal Charging Pump Room;
- Unit 2 6.9 kilovolt (kV) Non-Engineered Safety Feature (ESF) Switchgear Room;
- Division 22 Miscellaneous Electrical Equipment and Battery Room;
- Division 21 Miscellaneous Electrical Equipment and Battery Room; and
- 'B' Control Room Heating, Ventilation, and Air Conditioning Room.

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded, or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. The inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; fire detectors and sprinklers were unobstructed; transient material loading was within 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 six quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk-important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant areas to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- Essential Service Water train 'A' pump and valve rooms; and
- Essential Service Water train 'B' pump and valve rooms

This inspection constituted two internal flooding samples as defined in IP 71111.06–05.

b. Findings

No findings were identified.

1R07 Annual Heat Sink Performance (71111.07)

.1 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's testing of the 1B auxiliary feedwater pump lube oil heat exchanger to verify that identified thermal degradation did not mask the licensee's ability to detect additional degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors compared the licensee's observations with acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. The inspectors also verified that test acceptance criteria considered differences between test conditions and design conditions.

This annual heat sink performance inspection constituted one sample as defined in IP 71111.07–05.

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 March 24, 2015, the inspectors observed a crew of licensed operators in the plant's simulator during 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;
- the 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 February 27 and 28, 2015, the inspectors observed Byron operators remove SAT 242–1 and SAT 242–2 from service for a planned maintenance activity. The associated tasks required the operators to perform multiple bus transfers, equipment alignment changes, and paralleling operations with both the 2A and the 2B DGs. This was an activity that required heightened awareness. The inspectors evaluated the following areas:

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

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

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

- auxiliary feedwater system;
- fire protection system; and
- safety injection 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 structures, systems, and components (SSCs)/functions classified as (a)(2).

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)

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- Unit 2 component cooling water heat exchanger out-of-service, 0A non-essential service water pump out-of-service, 2A containment spray surveillance test, and Unit 2 pressurizer power-operated relief valve block valve surveillance tests during the week of January 12, 2015;
- 1A essential service water pump out of service, 2A auxiliary feedwater pump out of service, 2A RH pump suction line drained, and emergent 2C main steam power-operated relief valve repair during the week of February 2, 2015;
- Unit 1 200 megawatt electric (MWe) downpower, SAT–242 outage during the weekend of February 27, 2015, and Unit 2 continued operation with only one SAT (242–1 only);
- Unit 1 main power transformer fault and Unit 1 turbine/reactor trip concurrent with SAT 242–2 outage and low grid voltage condition on March 3, 2015; and
- Unit 1 startup activities and transformer testing with estimated Unit 2 transient grid voltage low and SAT 242–2 outage ongoing on March 9, 2015.

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

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- potential defects in ABB KF Relay ZPA;
- mud and silt fouling the tube side of the 1B auxiliary feed pump oil cooler;
- low lube oil pressure in 1A emergency DG turbocharger;
- 2B diesel oil storage tank (DOST) room flood barrier door repair;
- potential transient pressure in reactor coolant seal leakoff line during loss of seal cooling events;
- functionality determination of 0SX02PA/B–VIBL, essential service water makeup pump seismic restraint; and
- justification for containment floor drain level instrument to remain inoperable until refueling outage.

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 TSs and the UFSAR with 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 assessed compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sample of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

These operability inspections constituted seven samples as defined in IP 71111.15–05.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modifications:

- EC 400519, "Temporarily Bypass Condensate Storage Tank (CST) Heater 1CD01T–C Due to Controller Failure"; and
- EC 399110, "PDMS [Power Distribution Monitoring System] Upgrade to Beacon Version 6.7.3"

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

This inspection constituted two plant modification samples as defined in IP 71111.18–05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- adjustment of 2A DG fuel oil relief valve;
- Unit 1 turbine throttle valve #4 bistable switch failure; and
- preventative maintenance on essential service water train cross-tie valve 1SX034.

These activities were selected based upon the SSC's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against the 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 three PMT samples as defined in IP 71111.19–05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Other Outage Activities

a. Inspection Scope

The inspectors evaluated Unit 1 post-trip outage activities for an unscheduled outage that began on March 3, 2015, and continued through March 9, 2015. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule. The inspectors also reviewed open corrective actions to ensure that the licensee included operationally significant deficiencies in the outage schedule.

The inspectors observed or reviewed the post-trip actions including outage equipment configuration and risk management, electrical lineups for both units, selected clearances, control and monitoring of decay heat removal, control of containment activities, personnel fatigue management, startup and heatup activities, and identification and resolution of problems associated with the outage. Refer to Section 4OA3.1 of this report for more information on the cause of the trip and other activities related to the transient response.

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

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- 2BOSR 5.5.8.RH.5–2A, "Group A Inservice Testing (IST) Requirements for RHR Pump 2RH01PB" [IST];
- 1BOSR 5.5.8.AF.5–2B; "Unit One Group B IST Requirements for Diesel Driven Auxiliary Feedwater Pump 1AF01PB" [IST];
- 2BOSR 6.7.5–1; "Unit 2 2A Containment Spray Additive Flow Rate Verification" [Routine]; and
- 2BOSR 7.5.4–2; "Unit 2 Diesel Drivel Auxiliary Feedwater Pump Monthly Surveillance" [Routine].

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, sufficient to demonstrate operational readiness, and consistent with the system design basis;
- was plant equipment calibration correct, accurate, and properly documented;
- were as-left setpoints within required ranges; and was the calibration frequency in accordance with TSs, the USAR, plant procedures, and applicable commitments;
- was measuring and test equipment calibration current;
- was the test equipment used within the required range and accuracy; and were applicable prerequisites described in the test procedures satisfied;
- did test frequencies meet TS requirements to demonstrate operability and reliability;
- were tests performed in accordance with the test procedures and other applicable procedures;
- were jumpers and lifted leads controlled and restored where used;
- were test data and results accurate, complete, within limits, and valid;
- was test equipment removed after testing;
- was IST testing performed in accordance with the applicable version of Section XI, of the American Society of Mechanical Engineers (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 for safety-related instrument control surveillance tests, was reference setting data accurately incorporated in the test procedure;

- was equipment returned to a position or status required to support the performance of its safety function following testing;
- were all problems identified during the testing appropriately documented and dispositioned in the licensee's CAP;
- were annunciators and other alarms demonstrated to be functional and were alarm setpoints consistent with design documents; 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 and two inservice testing samples as defined in IP 71111.22, Sections–02 and–05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on February 11, 2015, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the Technical Support Center to determine whether the event classifications, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to assess whether the licensee staff was properly identifying weaknesses and entering them into the CAP. As part of the inspection, the inspectors reviewed the drill package.

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

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Scrams Per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams Per 7000 Critical Hours performance indicator (PI) for Byron Station Units 1 and 2 for the period from the first quarter 2014 through the fourth 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, IRs, event reports and NRC Integrated Inspection Reports for the period of January 1, 2014, through December 31, 2014, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator.

This inspection constituted two samples for Unplanned Scrams Per 7000 Critical Hours as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams With Complications PI for Byron Station Units 1 and 2 for the period from the first quarter 2014 through the fourth 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, IRs, event reports and NRC Integrated Inspection Reports for the period of January 1, 2014, through December 31, 2014, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's Issue Report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator.

This inspection constituted two samples for Unplanned Scrams with Complications as defined in IP 71151–05.

b. Findings

No findings were identified.

.3 Unplanned Transients Per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Transients Per 7000 Critical Hours PI for Byron Station Units 1 and 2 for the period from the first quarter 2014 through the fourth 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, IRs, maintenance rule records, event reports and NRC Integrated Inspection Reports for the period of January 1, 2014, through December 31, 2014, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and identified that on December 30, 2014, the licensee performed a downpower on Unit 1 to approximately 73 percent power to perform emergent maintenance in the switchyard on an insulator that was found degraded on December 29, 2014.

The licensee determined that this downpower should not be classified as unplanned because the load dispatcher directed the downpower. The licensee documented this determination in IR 2441512. The inspectors, after consultation with the Performance Indicator Program point of contact in the NRC's Office of Nuclear Reactor Regulation, determined that the guidance in NEI 99–02 did not support the licensee's determination. The inspectors discussed this view with the licensee and the licensee determined that a Frequently Asked Question (FAQ) would be submitted to the ROP Working Group to clarify this interpretation issue. The licensee documented this issue in the CAP as IR 2481584 and initiated the process of submitting the FAQ. Upon resolution of the FAQ, the NRC will publish the FAQ on the NRC website and the licensee will update the reported PI data, if necessary. Any potential changes to the PI as a result of this FAQ would not change the PI color.

This inspection constituted two Unplanned Transients Per 7000 Critical Hours samples 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 Security

.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 whether identification of the problem was complete and accurate; whether timeliness was commensurate with the safety significance; whether 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 whether 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 Selected Issue Follow-Up Inspection: Review of Unit 2 Safeguards Actuation Relay Train A Failure During Testing

a. Inspection Scope

While reviewing items entered in the licensee's CAP, the inspectors noted a corrective action item documenting the failure of Unit 2 Safeguards Actuation Relay Train "A" (SARA) during refueling outage B2R18 surveillance testing. The inspectors reviewed the licensee's troubleshooting, repair, and PMT as well as the licensee's extent of condition review, apparent cause evaluation, and past operability evaluation. The inspectors walked down the engineered safety feature cabinet that housed the Unit 2 SARA following repairs and interviewed licensee staff familiar with the licensee's CAP and foreign material exclusion program. The inspectors also reviewed the work packages and CAP documents for recent maintenance performed on the Unit 2 SARA and other similar safety-related relays on Units 1 and 2.

The inspectors assessed the following attributes while reviewing the licensee corrective actions associated with the issue:

- was the identified problem documented in the CAP in a complete, accurate, and timely manner;

- were operability and reportability issues evaluated and dispositioned in a timely manner;
- was extent of condition and previous occurrences considered;
- were corrective actions appropriately focused to correct the problem;
- was operating experience adequately evaluated for applicability; and
- were applicable lessons learned communicated to appropriate organizations and implemented.

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

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," when licensee personnel failed to establish appropriate controls to address potential foreign material that could be introduced during a modification activity on the Unit 2 SARA. Consequently, the Unit 2 SARA failed to actuate during a surveillance test.

Description: On September 30, 2014, while Unit 2 was shut down for a refueling outage, the licensee performed a surveillance test of the Unit 2 SARA. During this test, the Unit 2 SARA failed to actuate. The safeguards actuation relays were part of the engineered safety feature actuation system (ESFAS) and were safety-related relays that were required to energize to actuate engineered safety feature (ESF) equipment during a safety injection with offsite power available. The safeguards relays could also be manually actuated by the operators using a control switch. Technical Specification 3.3.2, "Engineered Safety Feature Actuation System Instrumentation," required that both trains of ESF actuation relays be operable in Modes 1–4 and with one train inoperable the licensee was required to restore the inoperable train to an operable status within 24 hours or place the plant in cold shutdown. However, Unit 2 was in Mode 5 during this surveillance test; therefore, the SARA was not required to be operable.

During troubleshooting, the licensee identified that a detached contact block from the SARA had fallen inside the relay, preventing it from changing position. The contact block did not serve a safety function as its purpose was limited to indicating visually whether the contact on the relay was normally open or normally closed. The licensee documented this issue in the CAP as IR 2388711 and performed an equipment apparent cause evaluation (EACE). The licensee's EACE identified that the apparent cause of the relay failure was foreign material (the contact block) generated when the licensee installed larger lugs on the relay for a timer replacement during the previous refueling outage. The licensee determined that these larger lugs applied stress on some of the contact blocks, causing them to shear off. This issue with relay contact blocks was first identified during timer replacement activities on Unit 1 in 2012.

The licensee also performed an extent of condition inspection on other safety-related relays of the same model on both Units 1 and 2 and found six contact blocks missing from relays. The licensee inspected the relays below those with missing contact blocks and did not identify any foreign material in the relays.

The inspectors reviewed IRs documenting prior instances of broken contact blocks. On September 15, 2012, while Unit 1 was shut down for a refueling outage, electrical maintenance technicians were disconnecting and removing timers in electrical cabinet 1PA13J as part of the planned timer replacement modification activity. During the timer removal, the technicians identified damaged contact blocks on two relays, the Unit 1 SARA and the Unit 1 safeguards shutdown relay train 'A' (SDRA). The technicians entered these issues into the CAP as IR 1413778 and IR 1413868.

The inspectors noted that after the broken contact blocks were identified, the licensee replaced the Unit 1 SARA and SDRA and determined that continuing to install the timer modification on Unit 1, and later on Unit 2, would identify any other broken contact blocks. The licensee completed replacing the timers on cabinet 1PA13J as well as 1PA14J, which housed the Unit 1 safeguards actuation relay train 'B' (SARB), and performed a post-work visual inspection of the cabinets. After the visual inspection of 1PA14J, the technician noted in the work package that no foreign material was left in the cabinet.

The inspectors noted that after the timer modification on Unit 1, the licensee performed a post-maintenance test to verify the proper operation of the equipment that was impacted by the work. During this PMT, the Unit 1 SARB failed to actuate and the licensee documented the failure in IR 1418907. The licensee's troubleshooting identified that the SARB failed to change position because a broken contact block had fallen into the relay, preventing normally open contacts from closing. The foreign material was removed, and the PMT was re-performed successfully. The licensee documented the foreign material in the same IR.

The inspectors reviewed the CAP documents from the Unit 1 foreign material event and the work instructions for the subsequent Unit 2 timer replacement and identified that although the licensee identified and documented that the modification activities were causing the contact blocks to break off the relays, the licensee took no action to address the foreign material aspects of the timer modification activities during the subsequent Unit 2 modification. Consequently, the licensee completed the timer replacement modification on Unit 2 on April 16, 2013, using work instructions that had not been updated to account for the foreign material aspects identified during the Unit 1 work. Following the Unit 2 modification, the modified Unit 2 relays appeared to be functional as they all satisfactorily passed their PMT. The relays were not functionally tested again until the next refueling outage in September 2014, when the Unit 2 SARA failed to actuate.

The licensee's immediate corrective actions included documenting the issue in the CAP as IR 2388711, replacing the relay, and inspecting same Mode 1 safety-related relays installed in the plant prior to Unit 2 entering Mode 4. The licensee did not identify any foreign material in the relays during these inspections.

<u>Analysis</u>: The inspectors determined that the licensee's failure to establish appropriate controls to address the potential foreign material generated by the timer replacement activities on Unit 2 was a performance deficiency. Specifically, Step 4.4.1 of maintenance procedure MA–AA–716–008, "Foreign Material Exclusion Program," stated that work planning should include identification of the potential foreign material associated with or generated by the activity and establish appropriate controls based on the equipment that could be exposed to foreign material and the work to be performed.

It also stated that work planning should use station operating experience to help identify risks and appropriate work practices. The inspectors identified that after the licensee identified broken contact blocks during the Unit 1 timer modification and the failed Unit 1 SARB test, the licensee did not add any guidance into the work instructions for the Unit 2 timer replacement to address the potential to generate foreign material that could adversely impact the operation of the relays. As a result, foreign material was generated by maintenance activities on Unit 2 and was not identified by the workers or by the PMT.

Using IMC 0612, "Appendix B-Issue Screening," issued September 7, 2012, the inspectors determined this performance deficiency was of more than minor significance because it was associated with the Mitigating Systems cornerstone attribute of Procedure Quality and adversely affected the cornerstone objective of ensuring the reliability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage).

The inspectors utilized Exhibit 2, "Mitigating Systems Screening Questions," of IMC 0609, Appendix A, "Significance Determination Process for Findings At-Power," dated June 19, 2012, to evaluate the significance. Because the finding was not a design or qualification deficiency; did not represent the loss of a system or function; and represented an actual loss of function of the 'A' train safety injection automatic actuation relay for greater than the TS Allowed Outage Time of 24 hours, a detailed risk evaluation by the regional Senior Reactor Analysts (SRAs) was required.

The SRAs evaluated the finding using the Byron Standardized Plant Analysis Risk (SPAR) model, version 8.27, Systems Analysis Programs for Hands-On Integrated Reliability Evaluations (SAPHIRE) version 8.1.2. The performance deficiency caused a risk increase on Unit 2 during conditions when a safety injection (SI) signal was actuated with offsite power available. The following conditions will generate an automatic SI signal: (1) pressurizer low pressure; (2) main steam line low pressure; and (3) containment high pressure.

The initiating events evaluated for this finding were loss of coolant accidents, main steam line breaks, main feedwater line breaks, and steam generator tube ruptures (a conservative assumption). The SARA relay function was to automatically start safety-related loads during an SI with offsite power available. Due to the performance deficiency, the relay would have failed to perform this function. The SRA identified the following loads that would be affected: charging pump 'A'; safety injection pump 'A'; RHR pump 'A'; component cooling water pumps 'A' and '0'; essential service water pump 'A'; and auxiliary feedwater pump 'A'. Containment spray pump 'A' was also affected, but its failure would not have caused a change in core damage frequency for this deficiency.

It is important to note that failure of the SARA relay would not prevent operators from manually starting the safety-related loads individually. Also, the relay failure would not prevent the sequencer from auto-starting safety-related loads during an SI without offsite power available because the sequencer function was actuated from a different relay.

The SARA relay operated satisfactorily during PMT on April 16, 2013. The relay failed its surveillance test on September 30, 2014. In accordance with guidance from the Risk Assessment of Operational Events (RASP) Handbook, a "t/2" exposure time based on these dates was calculated to be 266 days.

The SRA discussed changes to the Byron SPAR model to add the steam line and feed line break initiating events and manual recovery of SI loads with Idaho National Laboratory (INL) personnel. The steam line break initiator was added to the Byron model; however, after some preliminary work by INL, the feed line break initiators were effectively screened and not added to the Byron model based on several factors, including having very low importance for this issue. Treatment of manual recovery of SI loads was applied in this analysis using the SPAR-H human reliability analysis method. The SRA assumed high stress for diagnosis; all other performance shaping factors were assumed nominal. The SRA assigned a human error probability to manually recover the SI loads of 2.0E–02.

Solving the SPAR Model with these changes, the differential core damage frequency (ΔCDF) using an exposure time of 266 days was calculated to be 1.46E–07/year. The dominant sequence was a small break loss of coolant accident initiating event with RHR train ‘B’ unavailable due to test and maintenance. For external event accident initiators (i.e., seismic, fire, flooding), the SRA assumed that fire and flooding initiators would not contribute to the risk increase for this finding. For seismic events, the SRA conservatively assumed that any seismic-induced loss of offsite power (LOOP) event would also cause a high energy line break. Using the RASP handbook, the frequency of a seismic-induced LOOP event for Byron was 3.37E–05/year. This value was about an order of magnitude lower than the initiating event frequency for the dominant small break loss of coolant accident (LOCA) sequences. Thus, the SRA concluded that external event accident initiators would not significantly contribute to the risk associated with this finding.

Since the total estimated change in core damage frequency was greater than 1.0E–7/year, IMC 0609 Appendix H, “Containment Integrity Significance Determination Process,” was used to determine the potential risk contribution due to large early release frequency (LERF). Byron Station is a 4-loop Westinghouse pressurized water reactor with a large dry containment. Sequences important to LERF include steam generator tube rupture events and inter-system LOCA 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 (i.e., Green).

The finding had a cross-cutting aspect in the Evaluation component of the Problem Identification and Resolution cross-cutting area because the licensee failed to thoroughly evaluate the broken contact blocks on Unit 1 to ensure that resolutions address causes and extent of conditions commensurate with their safety significance. Specifically, the licensee identified that the Unit 1 relay failure during the PMT was caused by broken contact blocks, but failed to ensure that resolutions addressed this cause and the extent of this condition to the subsequent modification on Unit 2. (P.2)

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” required, in part, that activities affecting quality be prescribed by documented instructions of a type appropriate to the circumstances. Work Order 1495265 included the work instructions for replacing the timers in ESF cabinet 2PA13J, a safety-related cabinet.

Contrary to the above, on April 13, 2013, Byron Station failed to have work instructions appropriate to the circumstances for controlling foreign material such that it did not impact safety-related equipment. Specifically, after the licensee identified that the timer replacement activities on Unit 1 generated foreign material that adversely impacted the operation of safety-related relays, the licensee failed to incorporate that station operating experience into the work instructions for the Unit 2 modification controlled by WO 1495265. This resulted in foreign material entering the Unit 2 SARA, preventing its operation during surveillance testing on September 30, 2014.

The licensee's immediate corrective actions included documenting the issue in the CAP as IR 2388711, replacing the relay, and inspecting same Mode 1 safety-related relays installed in the plant prior to Unit 2 entering Mode 4. The licensee did not identify any foreign material in the relays during these inspections.

Because this violation was of very low safety significance and it was entered into the licensee's CAP, it is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000455/2015001–01, "Failure to Provide Work Instructions that Appropriately Address Foreign Material Exclusion from Safeguards Relays").**

.4 Selected Issue Follow-Up Inspection: Error Light Blinking on Seismic Monitor Equipment

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors noted a corrective action item documenting the licensee's identification of an "ERROR" light blinking on the seismic monitoring equipment in a panel in the auxiliary electrical equipment room. The associated issue report, IR 2464734, indicated that the licensee declared the seismic monitoring equipment inoperable in accordance with Technical Requirements Manual (TRM) 3.3.b, but stated that the issue did not meet any thresholds of the Exelon Reportability Manual. The inspectors reviewed other recent IRs related to the seismic monitoring system, the TRM, 10 CFR 50.72 requirements, as well as industry and licensee reportability guidance.

The inspectors assessed the following attributes while reviewing the licensee corrective actions associated with the issue:

- Was the identified problem documented in the CAP in a complete, accurate, and timely manner;
- Were operability and reportability issues evaluated and dispositioned in a timely manner;
- was extent of condition and previous occurrences considered;
- was operating experience adequately evaluated for applicability; and
- were applicable lessons learned communicated to appropriate organizations and implemented.

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

b. Findings

Introduction: The inspectors identified a Severity Level IV non-cited violation of 10 CFR 50.72(b)(3)(xiii) when licensee personnel failed to notify the NRC of a major loss of emergency assessment capability within 8 hours of the failure of the onsite seismic monitor used to classify an Emergency Action Level (EAL).

Description: On March 7, 2015, while performing a surveillance test of the station seismic monitoring instrumentation in panel 0PA02J in the Auxiliary Electrical Equipment Room, the licensee identified that the "ERROR" light on the central recorder of the seismic monitor was blinking. The licensee declared the seismic monitor inoperable and entered TRM Limiting Condition for Operation (TLCO) 3.3.b Required Action A.1 to restore the instrument to an operable status within 30 days. The licensee initiated IR 2464734 and repaired and restored the instrument to an operable status in less than 2 days.

The licensee's Emergency Plan EAL HA4, "Natural or destructive phenomena affecting vital areas," was the licensee's EAL to declare an Alert emergency classification due to an Operating Basis Earthquake (OBE) affecting the site. The threshold to declare this EAL required both an OBE indicated on the seismic instrumentation in panel 0PA02J and the earthquake confirmed by one of three other means. Therefore, with the seismic instrumentation in panel 0PA02J inoperable, the licensee was unable to classify EAL HA4 for an OBE.

According to 10 CFR 50.72(b)(3)(xiii), the licensee was required to notify the NRC within 8 hours of a major loss of emergency assessment capability. Licensee procedure EP–AA–120–1006, "EP Reportability–Loss of Emergency Preparedness Capabilities," Attachment 1, "Support Information," Example 5, stated that if the seismic monitoring system suffered a failure such that one seismic-related EAL could not be evaluated, this event would be reportable. The licensee added this guidance to their Emergency Preparedness reportability procedure following a similar issue at a different station in the licensee's fleet in which that station received a NCV from the NRC. On February 2, 2015, in IR 2446306, the licensee documented Byron's review of the issue at the other station, and stated that the reportability requirement applied to Byron as well. The IR stated that the procedure change to EP–AA–120–1006 was implemented at Byron on December 9, 2014, and that the procedure change and the element of seismic instrumentation inoperability being reportable as an emergency assessment capability reportability threshold was communicated to the shift managers.

Upon discovery of the inoperable seismic monitoring instrumentation, however, the licensee failed to make the notification within 8 hours as required by 10 CFR 50.72(b)(3)(xiii), and documented in IR 2464734 that the issue did not meet any of the thresholds contained in the Exelon Reportability Manual. On March 9, following review of recent CAP documents, the NRC inspectors questioned why the issue wasn't reported. The licensee reviewed the issue, determined that it was, in fact, reportable, and on March 12, made the required notification (Event Notice (EN) 50881) and initiated IR 2467719 to document the missed notification. The inspectors then identified that the licensee had failed to notify the NRC after a prior seismic monitor failure on November 6, 2014. The licensee performed a historical review and identified six failures of the seismic monitoring system in the 3 years prior to the March 7, 2015, occurrence and contacted the NRC to provide an update to EN 50881 to include these occurrences.

The licensee's corrective actions included initiating IR 2464734 and repairing the seismic monitoring instrumentation. The licensee also made the required notification on March 12, 2015, and initiated IR 2467719 to document the licensee's failure to notify the NRC within the required timeframe.

Analysis: The inspectors determined that the licensee's failure to assess the reportability of the inoperable seismic monitor in accordance with licensee reportability assessment procedures was a performance deficiency. Specifically, licensee procedure EP–AA–120–1006, "EP Reportability–Loss of Emergency Preparedness Capabilities," Attachment 1, "Support Information," Example 5, stated that a seismic monitor failure that affected the licensee's ability to evaluate a seismic-related EAL was reportable. Upon discovery that the licensee's seismic monitoring system failed, the licensee declared the seismic monitoring system inoperable, but failed to assess it as reportable and failed to make the required report to the NRC. The inspectors evaluated the performance deficiency using IMC 0612, "Appendix B–Issue Screening," issued September 7, 2012, and determined the issue was required to be screened in both the Reactor Oversight Process (ROP) and Traditional Enforcement (TE) areas. When the inspectors screened the finding using the ROP more-than-minor screening questions, the performance deficiency was determined to be not of more than minor significance because the inspectors answered all of the screening questions "No". Therefore, the issue did not represent a finding as defined in the ROP.

The inspectors determined that this issue had the potential to impact the regulatory process based, in part, on the generic communications input that 10 CFR 50.72 reports serve. Since the issue impacted the regulatory process, it was dispositioned through the TE process. The inspectors determined that this issue was a Severity Level IV violation based on Section 6.0, "Inaccurate and Incomplete Information or Failure to Make a Required Report," Example d.9 in the NRC Enforcement Policy. Example d.9 specifically includes, "A licensee fails to make a report required by 10 CFR 50.72 or 10 CFR 50.73," as an example of a Severity Level IV violation.

Because the inspectors did not identify an associated finding of more than minor significance and cross-cutting aspects were not assigned to TE violations, the inspectors did not assign a cross-cutting aspect to this issue.

Enforcement: Title 10 CFR Part 50.72(b)(3), "Eight-hour reports," requires, in part, "If not reported under paragraphs (a), (b)(1) or (b)(2) of this section, the licensee shall notify the NRC as soon as practical and in all cases within eight hours of the occurrence of any of the following…" (xiii) "any event that results in a major loss of emergency assessment capability."

Contrary to the above, on March 7, 2015, the licensee declared the seismic monitoring system inoperable, but failed to report the loss of the seismic monitoring as a major loss of emergency assessment capability until March 12, 2015.

The licensee's corrective actions included initiating IR 2464734 and repairing the seismic monitoring instrumentation. The licensee also made the required notification on March 12, 2015, and initiated IR 2467719 to document the licensee's failure to notify the NRC within the required timeframe. Because the issue was entered into the licensee's CAP as IR 2464734, the Severity Level IV violation is being treated as a NCV consistent with Section 2.3.2 of the NRC Enforcement Policy.

(NCV 05000454/2015001–02, 05000455/2015001–02, "Failure to Report Loss of Emergency Assessment Capability Following Seismic Monitoring System Failure").

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

.1 Unit 1 Automatic Reactor Trip

a. Inspection Scope

At 11:01 a.m. on March 3, 2015, Byron Unit 1 tripped due to a phase-to-phase fault on the 1E main power transformer (MPT) between phases 'A' and 'B'. The inspectors responded to the main control room and observed both the plant response to the event and operator actions taken in response to the event. The preliminary cause of the event identified by the licensee was a phase-to-phase arc caused by ice falling onto the transformer from the overhead electrical bus. The fault resulted in actuation of the generator differential current relays, 86G1A and 86G1B, and a turbine trip. The turbine trip resulted in a reactor trip. Operators responded in accordance with procedures and anticipated the automatic start of the auxiliary feedwater pump as steam generator water levels lowered by manually starting the 1A and 1B auxiliary feedwater pumps to maintain steam generator levels within the directed level band. No safety relief valves actuated during the transient and all safety systems responded as designed. The licensee reported the Reactor Trip System actuation and manual actuation of the auxiliary feedwater system in EN 50859 and in the CAP as IR 2462764.

The transformer was repaired and tested before being returned to service. Damage was limited to the high voltage and neutral bushings that were subsequently replaced. The reactor was restarted on March 8, 2015, and the generator was synchronized to the grid at 10:10 p.m. on March 9, 2015. The unit returned to full power at 08:25 p.m. on March 10, 2015.

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

b. Findings

No findings were identified.

.2 (Closed) Licensee Event Report 05000454–2015–001–00: Byron Unit 1, Inadequate Application of Technical Specifications Related to Main Steam Isolation Valves and Actuator Trains

On January 11, 2015, Byron Unit 2 entered TS 3.7.2, "Main Steam Isolation Valves (MSIVs)," Condition A, with an associated 1 hour Completion Time for the Unit 2, Train 'A' MSIV due to one of the two associated redundant actuator trains for the valve being inoperable. While this TS interpretation was consistent with an October 19, 2006, NRC staff interpretation that Surveillance 3.7.2.2 required both actuator trains for a single valve to be tested or the MSIV be declared inoperable, it was different than Byron Station had previously interpreted the TS. A subsequent review to determine the extent of condition of the issue identified two previous occurrences (one each for Unit 1 and Unit 2) within the past 3 years where an actuator train was inoperable for a valve and the inoperable train was not restored within the 8 hour required Completion Time.

Therefore, the event was reported as an operation or condition prohibited by the plant's TSs and the examples were included in the licensee event report (LER).

Byron had submitted a license amendment request (LAR) on August 21, 2013 to incorporate requirements specifically for the MSIV actuator trains within TS 3.7.2 such that the specification would include Conditions and Required Actions to address inoperable MSIV actuator trains. That LAR was approved by the NRC for Byron Station on January 30, 2015, and was subsequently implemented by the station. This LER is closed.

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

4OA6 Management Meetings

.1 Exit Meeting Summary

On April 16, 2015, the inspectors presented the inspection results to Mr. T. Chalmers, Byron Plant Manager, 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.

4OA7 Licensee-Identified Violation

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of the NRC Enforcement Policy for being dispositioned as an NCV.

- On January 2, 2015, operators implemented a plant barrier impairment (PBI) form to allow installation of a metal beam under the 1A DG rollup door (0DSSD166) to support work for the planned DG work window scheduled to begin on January 4. PBI 14–400 was created to support WO 1657636 and identified the type of barrier as a fire, security, and high energy line break (HELB) barrier. The PBI also identified the compensatory actions required to be in place when the PBI was implemented in order to satisfy the requirements of TRM 3.10.g, "Fire Assemblies." Barrier impairments were controlled by CC–AA–201, "Plant Barrier Control Program. In the case of this fire door, an hourly fire watch was specified in the PBI for this barrier, but was not implemented until January 4 when operators recognized the beam was not a qualified fire barrier. The required hourly fire watch was not in place for 33 hours and 28 minutes after the barrier was impaired. The Byron Unit 1 operating license (NPF–37) specified, in part, in Condition 2.C.(22) that Byron would develop and maintain strategies for addressing large fires and explosions considering, in part, minimizing the spread of fire. A key element to that strategy for fire barriers providing support for a credited safety function identified in the current licensing basis as documented in the Fire Protection Report and implemented in CC–AA–201 was the Plant Barrier Control Program. Technical Specification 5.4.1.c requires, in part, that written procedures be implemented and maintained covering Fire Protection Program Implementation. Contrary to the TS 5.4.1.c requirements specified above, the requirements of CC–AA–201 were not implemented to ensure that fire spread would be minimized in accordance with evaluated compensatory measures identified in the PBI and supporting documents.

The licensee immediately implemented the required hourly fire watch when the condition was identified. The issue was entered into the CAP as IR 2441189 and support procedures were revised to provide clarifying information regarding barrier impairment for DG rollup doors. The inspectors determined that this issue was more than minor because the performance deficiency adversely impacted the Design Control attribute of the Mitigating Systems cornerstone and adversely impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage) 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 inspectors determined the issue was of very low safety significance using IMC 0609 Appendix F, “Fire Protection Significance Determination Process.” The finding was characterized as 1.4.1, Fire Prevention and Administrative Controls. The inspectors answered "Yes" to Question 1.3.1 A and determined that the reactor could be safely shutdown since the vulnerability was limited to one safety train and suppression/detection systems remained functional during the entire period that compensatory measures were not in place.

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
L. Werner, Nuclear Oversight Manager
C. Keller, Engineering Director
R. Lloyd, Emergency Preparedness Manager
D. Spitzer, Regulatory Assurance Manager
L. Zurawski, NRC Coordinator
J. Fiesel, Maintenance Director
E. Hernandez, Operations Director
S. Kerr, Training Director

Nuclear Regulatory Commission

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

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000455/2015001–01	NCV	Failure to Provide Work Instructions that Appropriately Address Foreign Material Exclusion from Safeguards Relays (Section 4OA2.3.b)
05000454/2015001–02; 05000455/2015001–02	NCV	Failure to Report Loss of Emergency Assessment Capability Following Seismic Monitoring System Failure (Section 4OA2.4.b)

Closed

05000455/2015001–01	NCV	Failure to Provide Work Instructions that Appropriately Address Foreign Material Exclusion from Safeguards Relays (Section 4OA2.3.b)
05000454/2015001–02; 05000455/2015001–02	NCV	Failure to Report Loss of Emergency Assessment Capability Following Seismic Monitoring System Failure (Section 4OA2.4.b)
05000454/2015–001–00	LER	Byron Unit 1, Inadequate Application of Technical Specifications Related to Main Steam Isolation Valves and Actuator Trains (Section 4OA3.2)

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

- OP-AA-108-107-1001; Station Response to Grid Capacity Conditions; Revision 4
- EC 401329; Revision 000; Evaluation for Degraded Switchyard Voltage During Unit 2 Single SAT Operations for SAT 242-1
- IR 02463401; 4.0 Critique for OBOA ELEC-1
- OP-AA-111-1001; Severe Weather and Natural Disaster Guidelines; Revision 12
- IR 2439862; FHB Trainshed Inner Rollup Door ODSSD128 PBI Requirements
- UFSAR Section 2.4.2; Floods
- 0BOA ENV-1; Revision 114; Adverse Weather Conditions
- 1BOA ENV-1; Revision 101; Adverse Weather Conditions
- 2BOA ENV-1; Revision 101; Adverse Weather Conditions
- 0BOA ENV-2; Revision 102; Rock River Abnormal Water Level; Unit 0

Section 1R04

- M-66; Sheet 4D; Revision AQ; Diagram of Component Cooling
- M-66; Sheet 3A; Revision AV; Diagram of Component Cooling
- M-66; Sheet 3B; Revision AN; Diagram of Component Cooling
- BOP CC-10; Revision 29; Alignment of the U-0 CC Pump and U-0 CC HX to a Unit
- M-62; Sheet 1; Revision BE; Diagram of Residual Heat Removal
- M-54; Sheet 4A; Revision I; Diagram of Service Air (Diesel Generator Starting Air)
- BOP DG-1; Revision 18; Unit One-Two Diesel Generator Alignment to Standby Condition
- IR 1572048; High dP 1B DG Room Exhaust Fan
- M-61; Sheet 1A; Revision AY; Diagram of Safety Injection
- M-61; Sheet 1B; Revision AX; Diagram of Safety Injection
- M-61; Sheet 4; Revision AY; Diagram of Safety Injection
- BOP SI-E1; Revision 9; Unit 1 Safety Injection System (SI) Electrical Lineup

Section 1R05

- Pre-Fire Plan FZ 11.3D-1; Revision 0; Auxiliary Building 364'-0" Elevation 1A Centrifugal Charging Pump Room
- Pre-Fire Plan FZ 11.3A-1; Revision 0; Auxiliary Building 364'-0" Elevation 1A Safety Injection Pump Room
- WO 1653785; 0VA0265Y Damper Sticking
- IR 1518776; 0VA0265Y Damper Sticking – Create WR
- Pre-Fire Plan FZ 5.3-2; Revision 1; Auxiliary Building 451'-0" Elevation; Unit 2 6.9KV Non-ESF Switchgear Room
- Pre-Fire Plan FZ 5.4-2; Revision 1; Auxiliary Building 451'-0" Elevation; Division 22 Miscellaneous Electrical Equipment and Battery Room
- Pre-Fire Plan FZ 5.6-2; Revision 2; Auxiliary Building 451'-0" Elevation; Division 21 Miscellaneous Electrical Equipment and Battery Room

- Pre-Fire Plan FZ 18.4-2; Revision 1; Auxiliary Building 451'-0" Elevation; Control Room HVAC Equipment Room Train B
- Byron Fire Protection Report

Section 1R06

- IR 2345135; PBI BAP 1100-3A3 Compensatory Actions Non-Conservative
- IR 2381707; Recent ID Issue With SX Room Flood Seals Impact Planned Work
- IR 2406628; Issue With PBI 14-334
- Plant Barrier Impairment Permit ; PBI No. 14-334; dated August 25, 2014
- EC 400024; Revise Flood Calculation 3C8-1281-001
- EC 393060; Revise Auxiliary Building Flooding Calculation Zones G1-1A and G1-1B
- EC 399883; Revision 1; Impact of Potential Flood on SX Pump Room With Flood Seal Open
- CC-AA-201; Revision 10; Plant Barrier Control Program
- BAP 1100-3; Revision 23; Plant Barrier Impairment (PBI) Program
- IR 2448866; Watertight Door 0DSSD156 Failed Chalk Test

Section 1R07

- WO 1793315; 1B AF Pump Oil Cooler Outlet Temperature High
- WO 1796423; 1B AF Pump Surveillance
- 1BOSR 7.5.4-2; Unit One Diesel Driven Auxiliary Feedwater Pump Monthly Surveillance
- UFSAR Section 10.4.9; Auxiliary Feedwater System
- UFSAR Chapter 15.0; Accident Analysis
- EC 352392; Perform Owner's Acceptance Review of the Vendor Reports Issued to Address Historical Operability Study for the 1A AF Pump with No SX Cooling Available To the Lube Oil Cooler (Rev 1 for IR 283838)
- IR 2441727; 1B AF Pump Oil Cooler Has Significant Fouling
- IR 2423892; 1B AF Pump Oil Cooler Outlet Temperature High
- IR 2410861; 0A SXCT Intake Bar Rack Partially Blocked
- IR 0311626; As-found Tube Blockage Acceptance Criteria Not Met for 1AF01AB HX
- EC 355109; 1B AF Pump Oil Cooler Tube Blockage

Section 1R11

- Cycle 15-2 Evaluated Scenario

Section 1R12

- IR 2401711; Incorrect Acceptance Criteria Used for GL 89-13 HX
- IR 2473779; Fire Protection Maintenance Rule Condition Monitoring
- Maintenance Rule Expert Panel Meeting Notes; October 10, 2002
- Maintenance Rule Expert Panel Meeting Notes; July 3, 2002
- IR 2473786; FP Condition Monitoring Event Not Captured in Maintenance Rule
- Maintenance Rule Basis Document for Function FP-10; February 4, 2015
- IR 1636806; Pinhole Leak on FP Line in AB
- ER-AA-310-1004; Revision 13; Maintenance Rule – Performance Monitoring
- ER-AA-310-1003; Revision 4; Maintenance Rule – Performance Criteria Selection
- M-52; Sheet 7; Revision Z; Diagram of Fire Protection Auxiliary Building
- M-52; Sheet 1; Revision AI; Diagram of Fire Protection (Category I)
- 1BOA PRI-7; Revision 106; Essential Service Water Malfunction Unit 1

- VFPC5; Revision 5; Fire Protection System Area-5 FP Area 1-LL
- VFPC-7; Revision 5; Fire Protection System Area-7 FP Area 2-LL
- Maintenance Rule System Basis Document for Function FP-05; February 4, 2015

Section 1R13

- OP-AA-108-117; Revision 4; Protected Equipment Program
- IR 0311626; As-Found Tube Blockage Acceptance Criteria Not Met for 1AF01AB HX
- EC 355109; 1B AF Pump Oil Cooler Tube Blockage
- IR 2441727; 1B AF Pump Oil Cooler Has Significant Fouling
- IR 2423892; 1B AF Pump Oil Cooler Outlet Temperature High
- EC 352392; Perform Owner's Acceptance Review of the Vendor Reports Issued to Address Historical Operability Study for the 1A AF Pump with No SX Cooling Available to the Lube Oil Cooler (Rev 1 for IR 283838)
- IR 2444943; Aggregate Review of Potential WS/SX Cooling Operation
- EC 401329; Evaluation for Degraded Switchyard Voltage During Unit 2 Single SAT Operation for SAT 242-1

Section 1R15

- IR 2437309; Part 21 – 10CFR Notice Potential Defect RE: KF Relay ZPA
- IR 2438627; Part 21: ABB Notification of Potential Defect KF Relay ZPA
- Op Eval 15-001; ABB Part 21 Notification of Potential Defect for KF Relay ZPA
- Event Number 50691; Part 21 Report – Potential Defect Regarding KF Relays
- CTR-KF-SUM; Class 1E Relay Qualification Summary Report KF Under Frequency Relay; Revision 2 issued 1/20/2015
- IR 2441727; 1B AF Pump Oil Cooler Has Significant Fouling
- IR 2423892; 1B AF Pump Oil Cooler Outlet Temperature High
- EC 352392; Perform Owner's Acceptance Review of the Vendor Reports Issued to Address Historical Operability Study for the 1A AF Pump with No SX Cooling Available to the Lube Oil Cooler (Rev 1 for IR 283838)
- EC 355109; 1B AF Pump Oil Cooler Tube Blockage
- IR 02464129; Station Review of Westinghouse Infogram IG-15-1
- Information Notice (IN) 2003-19; Analyzed Condition of Reactor Coolant Pump Seal Leakoff Line During Postulated Fire Scenarios or Station Blackout
- IR 00183361; NRC IN 2003-19; Reactor Coolant Pump Seal Leakoff Line
- EC 401174; Revision 0; Functionality Determination of 0SX02PA/B-VIBL; SX Makeup Pump Seismic Restraint
- IR 1694034; NOS ID: Finding Restraint Not in ISI Plan
- BYR-13-0134; SX Makeup Pump Underwater Seismic Restraint
- IR 2448979; Unit 1 Containment Floor Drain Level Indication Suspect
- EC 401383; Evaluation for 1LI-PC003 Instrument to Remain Inoperable Until B1R20
- TRM 3.3.i; Post Accident Monitoring (PAM) Instrumentation
- 1BOA SEC-3; Revision 105; Loss of Condenser Vacuum; Unit 1
- OP-AA-103-102; Revision 13; Watch-Standing Practices
- BYR 13-092; Revision 0; Block Wall Evaluation
- OP-BY-102-106; Revision 7; Operator Response Time Program at Byron Station
- BOP CW-13; Revision 61; Isolating/Returning Condenser Waterbox to Service
- PBI 15-069; Plant Barrier Impairment Permit Evaluation for 2B DOST Door Repair; February 23, 2015
- IR 2470710; DOST Watertight Door PBI Expires March 23, 2015

Section 1R18

- CC-AA-112; Revision 21; Temporary Configuration Changes
- IR 2431137; U-1 CST Low Temp Alarm
- EC 400519; Revision 0; Temporarily Bypass Condensate Storage Tank (CST) Heater 1CD01T-C Due to Controller Failure
- WO 1797734; U-1 CST Low Temp Alarm
- 6E-1-4200; Revision G; Condensate Storage Tank Heaters & Manual Valves 1CD022; 1CD091
- 6E-1-4030CD18; Revision B; Condensate Storage Tank Heaters 1CD01T-A,B,C & D Local Control Panel 1CD02J
- EC 399110; PDMS Software Upgrade to Beacon Version 6.7.3

Section 1R19

- WO 1800884; Lower than Expected Fuel Oil Pressure – 2A DG
- BOP DG-11T2; Revision 17; Diesel Generator Operating Log
- IR 02460972; TV [Throttle Valve] #4 Bi-stable Malfunction
- 1BOL 3.1; Revision 11; LOCAR, Reactor Trip System (RTS) Instrumentation, Tech Spec LCO #3.3.1
- WO 01811594; TV #4 Bi-stable Malfunction
- WO 1672924; MOV PM; Actuator Inspection, Diagnostic Testing
- 1BOSR 0.5-2.SX.3-3; Revision 5; Unit One Position Indication Test of 1SX004, 1SX010, 1SX011, 1SX033, 1SX034, and 1SX136
- BOP SX-22; Revision 6; Essential Service Water Leak Isolation
- M-42; Sheet 1A; Revision AQ; Diagram of Essential Service Water

Section 1R20

- IR 02462764; Unit 1 Reactor Trip
- IR 02463416; 4.0 Response for U1 Reactor Trip
- IR 02462941; 2TE-TO001L TGTMS [Turbine Generator Temperature Monitoring System] Generator Temperature Alarm During Unit 1 Reactor Trip
- IR 2462974; Unit 1 MPT Disconnect Ground Switch B Phase Not Closing
- IR 2467844; B1F25 Lessons Learned 4.0 Critique of Ops Startup of Unit 1

Section 1R22

- WO 1780397; 1AF01PB Group B IST Requirements for Diesel Driven AF Pump
- 1BOSR 5.5.8.AF.5-2B; Unit One Group B Inservice Testing (IST) Requirements for Diesel Driven Auxiliary Feedwater Pump 1AF01PB
- WO 1782219; 2RH01PB Group A IST Requirements for Residual Heat Removal Pump
- 2BOSR 5.5.8.RH.5-2a; Revision 7; Group A Inservice Testing (IST) Requirements for Residual Heat Removal Pump 2RH01PB
- Design Information Transmittal (DIT) BYR-2001-003; Revision 0; Validation and Basis of RH Pump ASME Surveillance Acceptance Criteria
- WO 1764960; Unit 2 Train A Containment Spray Additive Flow Rate Verification
- 2BOSR 6.7.5-1; Revision 3; Unit Two 2A Containment Spray Additive Flow Rate Verification
- M-129; Sheet 1A; Revision AK; Diagram of Containment Spray
- M-129; Sheet 1B; Revision AL; Byron – Unit 2 Diagram of Containment Spray
- M-129; Sheet 1C; Revision AH; Diagram of Containment Spray

- 2BOL 6.7; Revision 4; LCOAR Spray Additive System Tech Spec LCO # 3.6.7
- WO 1808035; 2B Diesel Driven AF Pump monthly Surveillance
- 2BOSR 7.5.4-2; Revision 19; Unit Two Diesel Driven Auxiliary Feedwater Pump Monthly Surveillance
- AR 2453043; Received Unexpected Alarms and Indications in MCR for 2B AF
- WO 1807776; Received Unexpected Alarms and Indications in MCR for 2B AF
- 450-B50090; Revision 3; Auxiliary Feedwater Pump Lube System Schematic
- 451-B50090; Revision 0; Lube Oil Piping
- BAR 2AF01J-1-B3; Revision 53; Low oil Pressure 20 PSIG
- M-829; Revision AI; Instrument Location Elevation 383'-0" Auxiliary Building
- 6E-2-4030AF17; Revision E; Auxiliary Feedwater Pump 2B Gear Box Lube oil Pump 2AF01PB-C

<u>Section 4OA1</u>

- IR 2442230; NRC ID: Discrepancies Updating MSPI Basis Document
- IR 2430376; Bus 6 Support Insul – Ohio Brass – Top Petticoat 2nd Stack
- IR 2441512; December Unit 1 Load Drop for Insulator Planned or Unplanned
- IR 2481584; Need to Submit FAQ for December 2014 Downpower

<u>Section 4OA2</u>

- 2BOSR EF-1; Revision 5; Train A - SARA and ESF Sequencer Test – 2PA13J
- IR 2388711; SARA Sequencer Failed Testing – B2R18M4
- CC-AA-309-1012; 10 CFR Part 21 Technical Evaluations
- IR 1413868; Damaged Contact Blocks Identified in 1PA13J
- IR 1413778; Damaged Contact Blocks Identified in 1PA13J
- 6E-2-4030EF01; Revision O; Schematic Diagram ESF Sequencing and Actuation Cabinet Train A 2PA13J
- IR 1418907; 1BOSR EF-2 Train B Failed
- WO 1574082; Replace Damaged Contact Block Identified in 1PA13J
- WO 1495262; Replace "B" Train Eagle Timers 1PA14J per EC 372281
- WO 1427405; Train B ESF Sequencer
- WO 1574083; Replace Damaged Contact Block Identified in 1PA13J
- WO 1495265; Replace 'A' Train Eagle Timers 2PA13J per EC 372282
- IR 2390820; Damaged Relay Contact Blocks on "SARA" Relay in 2PA13J
- IR 2390492; 2A Train SARA Relay Failure
- WO 1773616; SARA Sequencer Failed Testing – B2R18M4
- LS-AA-120; Revision 14; Issue Identification and Screening Process
- MA-AA-716-008; Revision 9; Foreign Material Exclusion Program
- IR 2464734; Error Light Blinking on Seismic Monitor Equipment
- IR 2467719; Seismic Monitor Inoperability Is Reportable (EAL Assessment)
- 0BOSR 3.b.1-1; Revision 7; Unit Common Seismic Monitoring Instrumentation Monthly Surveillance
- EP-AA-120-1006; Revision 2; EP Reportability – Loss of Emergency Preparedness Capabilities
- IR 2446306; EP – Seismic Monitor Reportability
- 0BOL 3.b; Revision 2; LCOAR Seismic Monitoring Instrumentation TRM LCO # 3.3.b
- 0BVSR 3.b-1; Revision 4; Seismic Instrumentation Event Data Retrieval Surveillance
- IR 2445017; NRC Requested Review of SFCP for Enhancement

Section 4OA3

- IR 02462764; Unit 1 Reactor Trip
- IR 02463416; 4.0 Response for U1 Reactor Trip
- IR 02462941; 2TE-TO001L TGTMS Generator Temperature Alarm During Unit 1 Reactor Trip
- IR 2435783; Unexpected Low 2A MSIV Standby Accumulator Pressure/LCOAR Entry
- IR 2436822; Possible Missed LCO Entry For 6/30/14 2A MSIV Nitrogen Leak
- IR 1676838; Nitrogen Leakage from 2A MSIV Standby Accumulator 2PI-MS251A
- IR 1563273; 1B MSIV Has No Oil in Sight Glass
- IR 1676838; Nitrogen Leakage from 2A MSIV Standby Accumulator

Section 4OA7

- IR 2441189; BAP 1100-3A3 Enhancement for DG Rollup Doors
- EC 396376; MR90 Evaluation – Temporary Barrier For EDG Roll-up Doors to Facilitate Routing of Hoses and Cables for Maintenance Activities
- BAP 1100-3; Revision 24; Plant Barrier Impairment (PBI) Program
- CC-AA-201; Revision 11; Plant Barrier Impairment Program
- PBI 14-400; Door Fire/Security RS TB1 to 1DG01KA
- WO 1657636; Mechanical Inspection

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
AF	Auxiliary Feedwater
ASME	American Society of Mechanical Engineers
BAP	Byron Administrative Procedures
BOP	Byron Operating Procedures
CAP	Corrective Action Program
CC	Component Cooling
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CST	Condensate Storage Tank
DG	Diesel Generator
DIT	Design Information Transmittal
DOST	Diesel Oil Storage Tank
DRP	Division of Reactor Projects
EACE	Equipment Apparent Cause Evaluation
EAL	Emergency Action Level
EN	Event Notice
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
FAQ	Frequently Asked Question
FP	Fire Protection
FSAR	Final Safety Analysis Report
HELB	High Energy Line Break
IMC	Inspection Manual Chapter
IN	Information Notice
INL	Idaho National Laboratory
IP	Inspection Procedure
IR	Inspection Report
IR	Issue Report
IST	Inservice Testing
kV	Kilovolt
LAR	License Amendment Request
LCO	Limiting Condition for Operation
LCOAR	Limited Condition for Operation Action Requirement
LER	Licensee Event Report
LERF	Large Early Release Frequency
LIP	Local Intense Precipitation
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MPT	Main Power Transformer
MSIV	Main Steam Isolation Valve
MWe	Megawatt electric
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OBE	Operating Basis Earthquake
PARS	Publicly Available Records System

PBI	Plant Barrier Impairment
PDMS	Power Distribution Monitoring System
PI	Performance Indicator
PM	Planned or Preventative Maintenance
PMT	Post-Maintenance Testing
RASP	Risk Assessment of Operational Events
RHR	Residual Heat Removal
ROP	Reactor Oversight Process
SAPHIRE	Systems Analysis Programs for Hands-On Integrated Reliability Evaluations
SARA	Safeguards Actuation Relay Train ‘A’
SARB	Safeguards Actuation Relay Train ‘B’
SAT	System Auxiliary Transformer
SDRA	Safeguards Shutdown Relay Train ‘A’
SI	Safety Injection
SPAR	Standardized Plan Analysis Risk
SRA	Senior Reactor Analyst
SSC	Systems, Structures, and Component
TLCO	Technical Limiting Condition for Operation
TRM	Technical Requirements Manual
TS	Technical Specification
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
WO	Work Order

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/

Eric R. Duncan, Chief
Branch 3
Division of Reactor Projects

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

Enclosure:
IR 05000454/2015001; 05000455/2015001
w/Attachment: Supplemental Information

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