UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BLVD., SUITE 100
KING OF PRUSSIA, PA 19406-2713

February 11, 2015

EA-14-186

Mr. Bryan Hanson
Senior Vice President, Exelon Generation
President and Chief Nuclear Officer, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: OYSTER CREEK NUCLEAR GENERATING STATION – NRC INTEGRATED INSPECTION REPORT 05000219/2014005 AND PRELIMINARY WHITE FINDING

Dear Mr. Hanson:

On December 31, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Oyster Creek Nuclear Generating Station. The enclosed report documents the inspection results, which were discussed on January 29, 2015, with Mr. G. Stathes, Site Vice President, and other members of your staff. The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The enclosed inspection report discusses a finding associated with the failure of Emergency Diesel Generator (EDG) No. 2, which has preliminarily been determined to be White, a finding with low to moderate safety significance. As described in Section 4OA2 of the enclosed report, the finding is associated with an apparent violation of Title 10 of the *Code of Federal Regulations* (10 CFR) Appendix B, Criterion III, "Design Control," because Exelon did not review the suitability of a different maintenance process for tensioning the cooling fan belt on the EDGs. As a result, the new method imposed a stress above the fatigue endurance limit of the shaft material, making the EDG cooling fan shaft susceptible to fatigue and subsequent failure on July 28, 2014. As a consequence, Exelon also violated Technical Specification (TS) 3.7.C, since the EDG No. 2 was determined to be inoperable for greater than the technical specification allowed outage time.

The finding was assessed based on the best available information, using Inspection Manual Chapter (IMC) 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," issued June 19, 2012. The basis for the NRC's preliminary significance determination is described in the enclosed report. Because the finding is also an apparent violation of NRC requirements, it is being considered for escalated enforcement action in accordance with the Enforcement Policy, which appears on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html. The NRC will inform you, in writing, when the final significance has been determined. We intend to complete and issue our final safety significance determination within 90 days from the date of this letter. The NRC's SDP is designed to encourage an open dialogue between your staff and the NRC; however, the dialogue should not affect the timeliness of our final determination.

We believe that we have sufficient information to make a final significance determination. However, before we make a final decision, we are providing you an opportunity to provide your perspective on this matter, including the significance, causes, and corrective actions, as well as any other information that you believe the NRC should take into consideration. Accordingly, you may notify us of your decision within 10 days to: (1) request a regulatory conference to meet with the NRC and provide your views in person; (2) submit your position on the finding in writing; or, (3) accept the finding as characterized in the enclosed inspection report.

If you choose to request a regulatory conference, the meeting should be held in the NRC Region I office within 30 days of the date of this letter, and will be open for public observation. The NRC will issue a public meeting notice and a press release to announce the date and time of the conference. We encourage you to submit supporting documentation at least 1 week prior to the conference in an effort to make the conference more efficient and effective. If you choose to provide a written response, it should be sent to the NRC within 30 days of the date of this letter. You should clearly mark the response as "Response to Preliminary White Finding in Inspection Report No. 05000219/2014005; EA-14-186," and send it to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, Region I, and a copy to the NRC Senior Resident Inspector at the Oyster Creek Nuclear Generating Station.

You may also elect to accept the finding as characterized in this letter and the inspection report, in which case the NRC will proceed with its regulatory decision. However, if you choose not to request a regulatory conference or to submit a written response, you will not be allowed to appeal the NRC's final significance determination.

Please contact Silas Kennedy at (610) 337-5046 within 10 days from the issue date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision. Because the NRC has not made a final determination in this matter, no notice of violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violation may change based on further NRC review. The final resolution of this matter will be conveyed in separate correspondence.

In addition, the enclosed inspection report documents three violations of NRC requirements which were of very low safety significance (Green). However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations, consistent with Section 2.3.2.a of the NRC Enforcement Policy. If you contest the non-cited violations in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Oyster Creek Nuclear Generating Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding, 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 I, and the NRC Resident Inspector at the Oyster Creek Nuclear Generating Station.

In accordance with 10 CFR 2.390 of the NRCs "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 Public Document Room or from the Publicly Available Records component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Ho K. Nieh, Director
Division of Reactor Projects

Docket No.: 50-219
License No.: DPR-16

Enclosure: Inspection Report 05000219/2014005
Attachment 1: Detailed Risk Significance Evaluation
Attachment 2: Supplementary Information

cc w/encl: Distribution via ListServ

In accordance with 10 CFR 2.390 of the NRCs "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 Public Document Room or from the Publicly Available Records component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

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Attachment 2: Supplementary Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos.:	50-219
License Nos.:	DPR-16
Report No.:	05000219/2014005
Licensee:	Exelon Nuclear
Facility:	Oyster Creek Nuclear Generating Station
Location:	Forked River, New Jersey
Dates:	October 1, 2014 – December 31, 2014
Inspectors:	J. Kulp, Senior Resident Inspector A. Patel, Resident Inspector J. Schoppy, Senior Reactor Inspector P. Kaufman, Senior Reactor Inspector B. Fuller, Senior Operations Engineer R. Deese, Senior Reactor Analyst J. Viera, Operations Engineer E. Burkett, Emergency Preparedness Inspector B. Dionne, Health Physicist N. Floyd, Reactor Inspector M. Orr, Reactor Inspector J. Deboer, Reactor Engineer
Approved By:	Silas R. Kennedy, Chief Reactor Projects Branch 6 Division of Reactor Projects

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SUMMARY

IR 05000219/2014005; 10/01/2014 – 12/31/2014; Exelon Energy Company, LLC, Oyster Creek Nuclear Generating Station; Inservice Inspection Activities; Problem Identification and Resolution.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. Inspectors identified one apparent violation of with preliminary low to moderate safety significance (White) and three findings of very low safety significance (Green), which were also non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP), dated June 2, 2011. The cross-cutting aspects for the findings were determined using IMC 0310, "Aspects Within Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated July 9, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 5.

Cornerstone: Mitigating Systems

- Preliminary White. The inspectors identified a preliminary White finding and an associated apparent violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," because Exelon staff did not review the suitability of the application of a different maintenance process at Oyster Creek that was essential to a safety-related function of the emergency diesel generators (EDG). Specifically, in May 2005, Exelon staff changed the method for tensioning the cooling fan belt on the EDG from measuring belt deflection to belt frequency and did not verify the adequacy of the acceptance criteria stated for the new method. As a result, Exelon staff did not identify that the specified belt frequency imposed a stress above the fatigue endurance limit of the shaft material, making the EDG cooling fan shaft susceptible to fatigue and subsequent failure on July 28, 2014. As a consequence, Exelon also violated Technical Specification 3.7.C, because the EDG No. 2 was determined to be inoperable for greater than the technical specification allowed outage time. Exelon's immediate corrective actions included entering the issue into their corrective action program as issue report (IR) 1686101, replacing the EDG No. 2 fan shaft, examining the EDG No.1 fan shaft for extent of condition, and performing a failure analysis to determine the causes of the broken shaft.

  This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued June 19, 2012, the inspectors screened the finding for safety significance and determined that a detailed risk evaluation was required because the finding represented an actual loss of function of a single train for greater than its technical specification allowed outage time. The detailed risk evaluation concluded that the increase in core damage frequency was 5.1E-6, or White (low to moderate safety significance). This finding does not have an associated cross-cutting aspect because the performance deficiency occurred in 2005 and is not reflective of present performance. (Section 4OA2.4)

- Green. The inspectors identified a non-cited violation (NCV) of Technical Specification 6.8.1, “Procedures and Programs,” because Exelon did not adequately establish and maintain the plant shutdown procedure. Specifically, the procedure was not adequate in that it did not contain precautions concerning rod insertion when reactor power is below the point of adding heat; operational limitations on plant cooldown when power is below the point of adding heat; and contingency actions for re-criticality during shutdown. Exelon entered this issue into their corrective action program as IR 2412093 and conducted a root cause analysis.

  This finding is more than minor because it affected the procedure quality attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the reliability and capability of systems that respond to initiating events. Specifically, the plant shutdown procedure did not contain precautions to continuously insert control rods when reactor power is less than the point of adding heat, did not define operational considerations for limiting reactor cooldown, and did not contain contingency actions for return to criticality during shutdown. The inspectors screened this issue using IMC 0609.04, “Initial Characterization of Findings,” Exhibit 2 of IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” and IMC 0609 Appendix M, “Significance Determination Process Using Qualitative Criteria.” Inspectors determined this finding was of very low safety significance (Green). This finding has a cross-cutting aspect in the area of Human Performance, Documentation, because Exelon did not ensure that the shutdown procedure contained adequate controls for soft shutdown. [H.7] (Section 4OA2.5)

- Green. The inspectors identified an NCV of Technical Specification 6.8.1, “Procedures and Programs,” because Oyster Creek operators did not adequately implement procedures when performing a plant shutdown. Specifically, the operators did not ensure that all personnel on shift had received Just-in-Time-Training for their role in the shutdown; operators did not perform a reactivity Heightened Level Awareness brief for the shutdown, and did not insert source range monitors (SRMs) in accordance with procedure. These performance deficiencies contributed to two unanticipated criticalities during the shutdown. Exelon entered this issue into their corrective action program as IR 2412093 and conducted a root cause analysis.

  This finding is more than minor because it affected the procedure quality attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the reliability and capability of systems that respond to initiating events. Specifically, Exelon did not implement procedures during the plant shutdown which contributed to two unanticipated returns to criticality which required operator action to mitigate. The inspectors screened this issue using IMC 0609.04, “Initial Characterization of Findings,” Exhibit 2 of IMC 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” and IMC 0609 Appendix M, “Significance Determination Process Using Qualitative Criteria.” Inspectors determined this finding was of very low safety significance (Green). This finding has a cross-cutting aspect in the area of Human Performance, Procedure Adherence, because licensed operators did not implement processes, procedures and work instructions during the plant shutdown. [H.8] (Section 4OA2.5)

Cornerstone: Initiating Events

- Green. The inspectors identified an NCV of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” because Exelon did not promptly correct a condition adverse to quality associated with the reactor head cooling (RHC) spray line 2-inch upper flange which was installed in a configuration that exceeded the allowable acceptance criteria. Specifically, Exelon staff identified a misaligned flange condition in IR 845395 but did not correct the deficiency by evaluation, repair or replacement during the 1R22 refueling outage in 2008 or subsequently during the 1R23 and 1R24 refueling outages. Exelon staff completed corrective actions to replace the flange during the 1R25 refueling outage after the NRC inspector questioned the acceptability of this condition. Exelon staff entered this issue into their corrective action program as IR 2385501.

The finding is more than minor because it is associated with the equipment performance attribute of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, misalignment of the RHC spray line flange was greater than that provided in Oyster Creek pipe specifications and resulted in additional stresses in the flange weld. This condition was identified by Exelon staff as a possible contributor to the occurrence of a through wall crack and leak in the N7B upper flange socket weld joint that was identified and repaired in November 2012, but the misalignment was not corrected at that time. The inspectors screened this issue using IMC 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," and Exhibit 1 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," and determined this finding was of very low safety significance (Green). The inspectors determined that this finding had a Problem Identification and Resolution cross-cutting aspect because Exelon did not evaluate and take timely corrective actions to address the long-standing repetitive flange alignment issue of the reactor head cooling spray piping flange connection to reactor pressure vessel head N7B nozzle [P.2]. (Section 1R08)

REPORT DETAILS

Summary of Plant Status

Oyster Creek began the inspection period with the reactor shut down for the 1R25 refueling outage. Operators commenced a startup of the reactor on October 11, 2014. On October 12, 2014, an automatic scram occurred at approximately 1 percent power due to a human performance error which occurred during troubleshooting of the main generator automatic voltage regulator. Following repairs, Oyster Creek operators commenced startup on October 13, 2014, and the unit achieved 100 percent power on October 17, 2014. Operators briefly lowered power to 90 percent to perform rod pattern adjustments on October 18, 2014, October 24, 2014 and November 10, 2014. Operators lowered power to 95 percent on November 21, 2014 to perform turbine surveillances and returned to full power later the same day. The unit remained at or near 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01 – 3 samples)

.1 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors performed a review of Exelon's readiness for the onset of seasonal cold temperatures. The review focused on the intake structure and the EDGs. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), technical specifications, control room logs, and the corrective action program to determine what temperatures or other seasonal weather could challenge these systems, and to ensure Exelon personnel had adequately prepared for these challenges. The inspectors reviewed station procedures, including Exelon's seasonal weather preparation procedure and applicable operating procedures. The inspectors performed walkdowns of the selected systems to ensure station personnel identified issues that could challenge the operability of the systems during cold weather conditions.

b. Findings

No findings were identified.

.2 Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors reviewed Exelon's response to a tornado warning issued by the National Weather Service on November 8, 2014. The inspectors verified that Exelon implemented their adverse weather procedures and that operators monitored plant equipment that could have been affected by the adverse weather conditions. The inspectors performed walkdowns to verify that equipment in areas around the plant were maintained within procedural limits, and when necessary, compensatory actions were properly implemented in accordance with procedures. The inspectors also verified that

Exelon properly implemented its adverse weather procedures and that operators reviewed applicable emergency procedure. The inspectors performed independent walkdowns of the site to verify the site was ready for the onset of adverse weather.

a. Findings

No findings were identified.

.3 External Flooding

a. Inspection Scope

During the week of October 22, 2014, the inspectors performed an inspection of the external flood protection measures for Oyster Creek Nuclear Generating Station. The inspectors reviewed the UFSAR, Chapter 2.4.2, which depicted the design flood levels and protection areas containing safety-related equipment to identify areas that may be affected by external flooding. The inspectors conducted a general site walkdown of the EDG building to ensure that Exelon erected flood protection measures in accordance with design specifications. The inspectors also reviewed operating procedures for mitigating external flooding during severe weather to determine if Exelon planned or established adequate measures to protect against external flooding events.

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial System Walkdowns (71111.04Q – 4 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- Core spray system II during planned maintenance for core spray system I on November 12, 2014
- Containment spray system I during planned maintenance for containment spray system II on November 19, 2014
- 1-2 service water pump and both trains of emergency service water during planned maintenance on the 1-1 service water pump on December 8, 2014
- 1-2 and 1-3 turbine building closed cooling water pumps and both EDGs during planned maintenance on the 1-1 turbine building closed cooling water pump on December 9, 2014

The inspectors selected these systems based on their risk-significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors reviewed applicable operating procedures, system diagrams, the UFSAR, technical specifications, work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have impacted system performance of their intended safety functions. The inspectors also performed field walkdowns of accessible portions of the systems to verify system components and support equipment were aligned correctly and were operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no deficiencies. The inspectors also reviewed whether Exelon staff had properly identified equipment issues and entered them into the corrective action program for resolution with the appropriate significance characterization.

b. Findings

No findings were identified.

1R05 Fire Protection

.1 Resident Inspector Quarterly Walkdowns (71111.05Q – 3 samples)

a. Inspection Scope

The inspectors conducted tours of the areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that Exelon controlled combustible materials and ignition sources in accordance with administrative procedures. The inspectors verified that fire protection and suppression equipment was available for use as specified in the area pre-fire plan, and passive fire barriers were maintained in good material condition. The inspectors also verified that station personnel implemented compensatory measures for out of service, degraded, or inoperable fire protection equipment, as applicable, in accordance with procedures.

- Condenser bay (TB-FZ-11E) on October 9, 2014
- Drywell & Torus (RB-FA-2) on October 10, 2014
- Northeast corner room (RB-FZ-1F4) on October 28, 2014

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06 – 1 sample)

.1 Internal Flooding Review

a. Inspection Scope

The inspectors reviewed the UFSAR, the site flooding analysis, and plant procedures to assess susceptibilities involving internal flooding. The inspectors also reviewed the corrective action program to determine if Exelon identified and corrected flooding problems and whether operator actions for coping with flooding were adequate. The inspectors also focused on the containment spray system areas to verify the adequacy of equipment seals located below the flood line, floor and water penetration seals, watertight door seals, common drain lines and sumps, sump pumps, level alarms, control circuits, and temporary or removable flood barriers.

b. Findings

No findings were identified.

1R08 In-Service Inspection Activities (71111.08 – 1 sample)

a. Inspection Scope

The inspectors conducted a review of Exelon's implementation of in-service inspection (ISI) program activities for monitoring degradation of the reactor coolant system pressure boundary, risk significant piping and components, and containment systems for the Oyster Greek Nuclear Generating Station. The sample selection was based on the inspection procedure objectives and risk priority of those pressure retaining components in these systems where degradation would result in a significant increase in risk. The inspectors observed in-process non-destructive examinations (NDE), reviewed documentation, and interviewed inspection personnel to verify that the NDE activities performed as part of the Oyster Creek ISI during the 1R25 outage were conducted in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI, 2007 Edition, 2008 Addenda.

NDE and Welding Activities (IMC Section 02.01)

The inspectors observed portions of NDE activities in process and reviewed the nondestructive examinations data records listed below:

ASME Code Required Examinations

Activities inspected included direct field observations of manual and automated ultrasonic testing (UT), visual testing (VT), and dye penetrant (PT) testing. The inspectors reviewed the applicable NDE procedures, qualification certification for the personnel and procedures, and confirmed that relevant indications were properly documented and dispositioned. The inspectors reviewed a sample of certifications of the NDE technicians performing the examinations and verified that the inspections were performed in accordance with approved procedures and that the results were reviewed and evaluated by certified Level III NDE personnel.

The inspectors observed portions of the following in-process NDE activities, including review of the examination documentation data records:

- Manual UT of reactor recirculation system 'E' pump suction piping valve to elbow weld NG-E-0007 (UT examination report UT-14-052);
- PT testing of the RHC vent pipe-slip on flange weld RHC-2-60 (PT examination reports BOP-PT-2014-013 and BOP-PT-2014-14);
- Automated encoded phased array UT of reactor vessel top closure head spray flange to nozzle N7A dissimilar metal weld NR02/02-576 (phased array examination report 1-B5-10.0010);
- Automated encoded phased array UT of reactor vessel top closure head spray flange to nozzle N7B dissimilar metal weld NR02/4-576 (phased array examination report 1-B5-10.0020);

- Automated encoded phased array UT of reactor vessel top closure head vent flange to nozzle N8 dissimilar metal weld NR02/6-576 (phased array examination report 1-B5-10.0024); and,
- VT examination of drywell sand bed bay 9 for epoxy coating anomalies and for corrosion.

The inspectors reviewed the following NDE data records:

- Automated encoded phased array UT data of isolation condenser nozzles N5A and N5B safe-end dissimilar metal welds;
- Automated encoded phased array UT data of reactor recirculation system reactor vessel outlet safe-end-to-nozzle dissimilar metal welds N1A, N1C, and N1D;
- VT examination reports of sand bed bays 1, 3, 5, 7, 13 ,17, and 19 and UT thickness measurements taken in these sand bed bays; and,
- PT examination data records of reactor vessel top closure head flange to nozzle N7B upper pipe/flange replacement during 1R25 outage. (See Repair/Replacement Activities below)

<u>Other Augmented or Industry Initiative Examinations</u>

The inspectors reviewed inspection records of visual inspections conducted of the reactor vessel internal components. The inspectors verified that the activities were performed in accordance with applicable examination procedures and industry guidance. The inspections were performed in accordance with the Boiling Water Reactor Vessel and Internals Project, In-Vessel Visual Inspection Program. The inspectors reviewed the VT examination data records and the disposition of identified indications.

The inspections during the 1R25 outage monitored and recorded the condition of the following reactor vessel internal components: reactor pressure vessel attachment welds; steam dryer; feedwater spargers; core shroud; shroud tie rod; core spray piping and spargers; top guide; and, fuel support casting.

<u>Review of Originally Rejectable Indications Accepted by Evaluation</u>

One sample was reviewed during this inspection that involved examinations with recordable indications that was accepted for continued service from the current 1R25 outage. The indication documented in IR 2386495 was on the reactor recirculation system ‘B’ loop decontamination port piping identified during a PT examination and was considered outside diameter stress corrosion cracking which was removed by surface buffing and the results were evaluated and determined to be acceptable for continued service.

<u>Modification/Repair/Replacements Consisting of Welding on Pressure Boundary Risk Significant Systems</u>

Exelon staff planned to replace the RHC spray line 2-inch upper flange per work order C20300107 during the 1R25 refueling outage but it was de-scoped from the planned list of outage activities. However, during a follow-up confirmation PT examination of the previously repaired 2-inch upper flange to pipe socket weld the NRC inspectors observed the 2-inch upper flange was noticeably out of level and requested the NDE technician at the worksite to photograph the condition. The inspectors informed appropriate Exelon NDE staff who initiated IR 2385501 on September 24, 2014. Exelon's corrective actions were to put the RHC spray line 2-inch upper flange replacement back into the 1R25 outage scope and the flange was replaced on September 30, 2014.

The inspectors reviewed the documentation associated with the replacement of RHC spray line 2-inch 1500 pound stainless steel upper flange connection to the reactor pressure vessel closure head N7B nozzle. The inspectors reviewed the replacement work order, welding documentation, and the PT data records to verify that the welding activities and applicable NDE activities were performed in accordance with ASME Code requirements.

Identification and Resolution of Problems (02.05)

The inspectors reviewed a sample of action requests, which identified NDE indications, deficiencies and other nonconforming conditions since the previous 1R24 outage and during the present 1R25 outage. The inspectors verified that nonconforming conditions were properly identified, characterized, evaluated, corrective actions identified and dispositioned, and appropriately entered into the Oyster Creek corrective action program.

b. Findings

Reactor Head Cooling Spray Line Flange

Introduction: The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," because Exelon did not promptly correct a condition adverse to quality associated with the RHC spray line 2-inch upper flange which was installed in a configuration that exceeded the allowable acceptance criteria.

Description: On September 23, 2014, the NRC inspectors observed the upper pipe flange on the 2-inch RHC spray line connection to the reactor pressure vessel closure head was visibly out of parallel. This flange is attached to piping via a socket weld. As part of reactor reassembly after a refueling outage, this flange is bolted to an adjacent flange of a short pipe spool piece that is then bolted to the reactor pressure vessel at nozzle N7B. The inspectors noted the observed flange misalignment could increase stresses in the flange socket weld and adjacent components and questioned the acceptability of this condition. In response to the inspectors' questions, Exelon staff entered the issue into their corrective action program in IR 2385501 for further evaluation.

In IR 2385501, Exelon staff indicated the out-of-alignment condition could have resulted from a weld repair of the flange socket weld on November 26, 2012, during the previous refueling outage (1R24). Additionally further misalignment could have been introduced by welding recently completed during the current refueling outage (1R25) to replace an adjacent check valve (V-31-5).

The inspectors reviewed the maintenance history of the flange and determined the RHC spray line was bent on October 27, 2008, during the 1R22 refueling outage while removing the RPV closure head mirror insulation with the Reactor Building overhead crane. Exelon's corrective action to resolve the bent/damaged spray piping was documented in IR 836642 which included a cold spring stress evaluation as a contingency if the damaged piping was not replaced. Exelon staff provided the cold spring evaluation to the inspector and indicated this evaluation was not utilized because the visibly bent/damaged portion of piping was replaced during the 1R22 refueling outage up to the reactor pressure vessel head N7B nozzle, with the exception of the 2-inch upper flange on the RHC spray line and a short pipe and tee connection. The inspectors noted the evaluation, if utilized, would have only supported a single operating cycle. Exelon staff performed PT examinations of the 2-inch piping welds and flange socket weld that were not replaced and determined there were no indications of surface cracks.

The inspector's review of the maintenance documentation identified that the upper N7B flange remained misaligned after pipe replacement in the 1R22 refueling outage. In review of IR 845395, the inspectors determined that on November 14, 2008, Exelon staff identified during reactor reassembly the upper N7B flange was "approximately .25 inches out of parallel." This exceeded quantitative guidance provided in Exelon procedure CC-AA-407, "Maintenance Specification: Evaluation and Repair of Piping and Equipment Flanges," Section 5.2.1. As a result, inspectors determined that the upper flange misalignment was a condition adverse to quality in accordance with Exelon procedure PI-AA-125, "Corrective Action Program," which defines a condition adverse to quality as an all-inclusive term used in reference to any of the following: failures, malfunctions, deficiencies, defective items, and non-conformances. An action to replace the flange during the next refuel outage was tracked as an action in the work order system. The inspectors observed this condition was not entered into the corrective action program for evaluation of acceptability to defer this repair. The work order to replace the flange was subsequently removed by Exelon staff from the next three refueling outage work scopes (1R23, 1R24 and 1R25) without evaluation as to whether the misalignment was acceptable.

The inspectors noted this misalignment likely contributed to a leak at the flange socket weld joint. During the nuclear steam supply system leak test on November 26, 2012, Exelon staff observed a through-wall leak in the N7B upper flange socket weld. Exelon staff completed a localized weld repair of the socket weld with the flange remaining bolted in accordance with the ASME Boiler and Pressure Vessel Code, Section XI. Exelon staff completed an apparent cause evaluation under IR 1444414 and concluded the socket weld through-wall crack resulted from the RHC spray piping being bent on October 27, 2008. This condition induced mechanical stresses resulting in a defect in the socket weld base metal interface of the RHC spray line 2-inch upper flange. Exelon's apparent cause evaluation also documented a contributing cause involving "possible flange misalignment," noting that residual stresses caused by misalignment may have contributed to the flaw propagation. However, the inspectors noted the apparent cause evaluation did not reference IR 845395, which identified an actual misaligned condition of approximately .25 inches.

The apparent cause evaluation also noted that during flange disassembly in 1R24 the bolts had to be cut. Upon further discussions with Oyster Creek station personnel the inspectors determined it was common practice to cut the RHC spray line flange bolts during reactor pressure vessel closure head piping disassembly activities because the bolts were seized. The inspectors confirmed this problem in review of IR 845395, IR 1135047, IR 1441461, IR 1441468, and IR 1430492. These IRs ensured the bolts were replaced as a corrective action but did not result in a corrective action to evaluate the misaligned flange as acceptable. Exelon staff revised procedure MA-OC-205-001, “Reactor Pressure Vessel Disassembly,” to add a note that these bolts seize and require cutting.

Exelon staff completed corrective actions to replace the 2-inch RHC spray line upper flange on September 30, 2014 during the 1R25 refuel outage. The inspectors reviewed the associated documentation including the replacement work order, welding documentation, and the PT data records and verified that the welding activities and applicable non-destructive examination activities were performed in accordance with applicable ASME Boiler and Pressure Vessel Code requirements.

Analysis: The inspectors determined that Exelon did not take prompt corrective actions, in accordance with 10 CFR 50, Appendix B, Criterion XVI, to address misalignment of the reactor head cooling spray piping flange, which was a performance deficiency that was within Exelon’s ability to foresee and correct. The finding is more than minor because it is associated with the equipment performance attribute (a misaligned flange) of the Initiating Events cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, misalignment of the RHC spray line flange was greater than that provided in Oyster Creek pipe specifications and resulted in additional stresses in the flange weld. This condition was described by Exelon staff as a possible contributor to the occurrence of a through wall crack and leak in the N7B upper flange socket weld joint that was identified and repaired in November 2012, but the misalignment was not corrected at that time. This issue is also similar to example 4.f in IMC 0612, Appendix E, “Examples of Minor Issues,” because the observed flange misalignment could increase stresses in the flange socket weld and adjacent components, and likely contributed to a leak at the flange socket weld joint.

The inspectors completed IMC 0609.04, “Phase 1 – Initial Screening and Characterization of Findings,” and screened the finding as very low safety significance (Green). Using Exhibit 1 of IMC 0609, Appendix A, the inspectors answered “No” to Question 1 because the worst-case degradation would be a small leak from a fatigue crack caused by operating thermal and/or mechanical loads combined with cold spring stresses. The inspectors answered “No” to Question 2 because the degradation would only result in a small leak in the Schedule 80 socket weld of RHC spray line 2-inch upper flange connection and would not have affected other systems used to mitigate a loss of coolant accident. Based on the leakage observed from the pinhole location in the 2-inch socket weld during the 1R24 outage reactor leak test (conducted at 1030 psig, 206 degrees F) the reactor coolant leak rate would likely be much less than the technical specification limit of 5 gallons per minute (gpm) unidentified leakage and leakage would not be expected to increase greater than the make-up capacity of a control rod drive pump (110 gpm). Additionally, operations personnel could have manually depressurized the reactor pressure vessel if needed and all other mitigating systems equipment was available.

The inspectors determined that this finding had a Problem Identification and Resolution cross-cutting aspect because Exelon did not thoroughly evaluate and take timely corrective actions to address the long-standing repetitive flange alignment issue of the reactor head cooling spray piping flange connection to the reactor pressure vessel head N7B nozzle (P.2).

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to the above, since identification in IR 845395, dated November 14, 2008, Exelon staff did not correct a condition adverse to quality regarding the non-conforming, 2-inch RHC spray line upper flange connection to the reactor pressure vessel head N7B nozzle that was misaligned greater than that allowed by their maintenance specification. Exelon's corrective action to restore compliance consisted of replacing the 2-inch RHC spray line upper flange on September 30, 2014. Because this issue is of very low safety significance (Green) and Exelon entered this issue into their corrective action program as IR 2385501, this finding is being treated as an NCV consistent with Section 2.3.2 of the Enforcement Policy. **(NCV 05000219/2014005-01, Reactor Head Cooling Spray Piping Flange Misalignment)**

1R11 Licensed Operator Requalification Program (71111.11Q – 3 samples)

.1 Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on October 21, 2014, which included a loss of B1 bus coincident with a large break loss of coolant accident and the failure of the No. 2 EDG. The inspectors also observed licensed operator simulator training on November 5, 2014, which included a loss of core spray system I coincident with a large break loss of coolant accident and the failure of the No. 1 EDG. The inspectors evaluated operator performance during the simulated event and verified completion of risk significant operator actions, including the use of abnormal and emergency operating procedures. The inspectors assessed the clarity and effectiveness of communications, implementation of actions in response to alarms and degrading plant conditions, and the oversight and direction provided by the control room supervisor. The inspectors verified the accuracy and timeliness of the emergency classification made by the shift manager and the technical specification action statements entered by the shift technical advisor. Additionally, the inspectors assessed the ability of the crew and training staff to identify and document crew performance problems.

b. Findings

No findings were identified.

.2 Quarterly Review of Licensed Operator Performance in the Main Control Room

a. Inspection Scope

The inspectors observed licensed operator performance during plant startup activities following refueling outage 1R25 on October 13, 2014. The inspectors observed infrequently performed test or evolution briefings, pre-shift briefings, and reactivity control briefings to verify that the briefings met the criteria specified in Exelon's Operations Section Expectations Handbook and Exelon Administrative Procedure OP-AA-329, "Conduct of Infrequently Performed Tests and Evolutions," Revision 1. Additionally, the inspectors observed test performance to verify that procedure use, crew communications, and coordination of activities between work groups similarly met established expectations and standards.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12 – 1 sample)

a. Inspection Scope

The inspectors reviewed the sample listed below to assess the effectiveness of maintenance activities on structures, systems or components performance and reliability. The inspectors reviewed system health reports, corrective action program documents, maintenance work orders, and maintenance rule basis documents to ensure that Exelon was identifying and properly evaluating performance problems within the scope of the maintenance rule. For each sample selected, the inspectors verified that the structure, system or component was properly scoped into the maintenance rule in accordance with 10 CFR 50.65 and verified that the (a)(2) performance criteria established by Exelon staff was reasonable. As applicable, for a structure, system or component classified as (a)(1), the inspectors assessed the adequacy of goals and corrective actions to return the structure, system or component to (a)(2). Additionally, the inspectors ensured that Exelon staff was identifying and addressing common cause failures that occurred within and across maintenance rule system boundaries.

- Turbine building closed cooling water system on December 24, 2014

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 3 samples)

a. Inspection Scope

The inspectors reviewed station evaluation and management of plant risk for the maintenance and emergent work activities listed below to verify that Exelon performed the appropriate risk assessments prior to removing equipment for work. The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that Exelon personnel performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When Exelon performed emergent work, the inspectors verified that operations personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work and discussed the results of the assessment with Exelon's risk analyst to verify plant conditions were consistent with the risk assessment. The inspectors also reviewed the technical specification requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

- Core spray system 1 maintenance window on November 12, 2014

- Standby liquid control system inservice and surveillance testing on December 1, 2014
- Unplanned corrective maintenance on the ‘A’ isolation condenser makeup valve operating switch on December 16, 2014

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 1 sample)

a. Inspection Scope

The inspectors reviewed operability determinations for the following degraded or non-conforming conditions:

- Isolation condenser makeup capabilities with the normal fire system isolated for leak repair on November 28, 2014

The inspectors selected this sample based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the operability determination to assess whether technical specification 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 technical specifications and UFSAR to Exelon’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 by Exelon. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18 – 2 samples)

.1 Temporary Modifications

a. Inspection Scope

The inspectors reviewed the temporary modifications listed below to determine whether the modifications affected the safety functions of systems that are important to safety. The inspectors reviewed 10 CFR 50.59 documentation and post-modification testing results, and conducted field walkdowns of the modifications to verify that the temporary modifications did not degrade the design bases, licensing bases, and performance capability of the affected systems.

- Temporary change to the ‘B’ battery room ventilation during cold temperatures
- Temporary change to the condensate storage tank level instrumentation

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 – 4 samples)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests for the maintenance activities listed below to verify that procedures and test activities ensured system operability and functional capability. The inspectors reviewed the test procedure to verify that the procedure adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure was consistent with the information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test or reviewed test data to verify that the test results adequately demonstrated restoration of the affected safety functions.

- Refurbishment of main steam isolation valve (V-1-8) on October 8, 2014
- Containment spray motor 1-1 after oil change and general inspection on October 27, 2014
- Replace A core spray booster pump (P-20-2A) undervoltage time delay relay on November 11, 2014
- Troubleshoot and repair of C1 battery charger on December 11, 2014

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20 – 1 sample)

a. Inspection Scope

Oyster Creek began the inspection period shutdown for the 1R25 Refueling outage, which began on September 15, 2014. The inspectors reviewed the station's work schedule and outage risk plan for the refueling outage, which was conducted September 15 through October 15, 2014. The inspectors reviewed Exelon's development and implementation of outage plans and schedules to verify that risk, industry experience, previous site-specific problems, and defense-in-depth were considered. The inspectors observed Exelon's performance during plant startup activities following the refueling outage on October 11-12, 2014. The reactor automatically scrammed, at approximately 1 percent power, due to a human performance error during troubleshooting of the main generator automatic voltage regulator. Following repairs, the inspectors observed Exelon's performance during plant startup on October 13, 2014. Exelon placed the generator on the grid on October 15, 2014. During the outage, the inspectors monitored controls associated with the following outage activities:

- Configuration management, including maintenance of defense-in-depth, commensurate with the outage plan for the key safety functions and compliance with the applicable technical specifications when taking equipment out of service
- Implementation of clearance activities and confirmation that tags were properly hung and that equipment was appropriately configured to safely support the associated work or testing
- Status and configuration of electrical systems and switchyard activities to ensure that technical specifications were met
- Monitoring of decay heat removal operations
- Impact of outage work on the ability of the operators to operate the spent fuel pool cooling system
- Reactor water inventory controls, including flow paths, configurations, alternative means for inventory additions, and controls to prevent inventory loss
- Activities that could affect reactivity
- Maintenance of secondary containment as required by technical specifications
- Identification and resolution of problems related to refueling outage activities

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 5 samples)

a. Inspection Scope

The inspectors observed performance of surveillance tests and/or reviewed test data of selected risk-significant structures, systems or components to assess whether test results satisfied technical specifications, the UFSAR, and Exelon procedure requirements. The inspectors verified that test acceptance criteria were clear, tests demonstrated operational readiness and were consistent with design documentation, test instrumentation had current calibrations and the range and accuracy for the application, tests were performed as written, and applicable test prerequisites were satisfied. Upon test completion, the inspectors considered whether the test results supported that equipment was capable of performing the required safety functions. The inspectors reviewed the following surveillance tests:

- Automatic depressurization system actuation circuit test and calibration on October 8, 2014
- Main steam isolation valve leak rate test (South Header) (V-1-8/NS-03B & V-1-10/NS-04B) on October 24, 2014
- Containment spray and emergency service water system 1 pump operability and quarterly inservice test on October 27, 2014
- Safety relief valve inservice test on October 29, 2014
- Loss of offsite power and loss of coolant accident actuation test for the No. 2 EDG on November 6, 2014

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

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

a. Inspection Scope

Exelon implemented various changes to the Oyster Creek Emergency Action Levels (EALs), Emergency Plan, and Implementing Procedures. Exelon had determined that, in accordance with 10 CFR 50.54(q)(3), any change made to the EALs, Emergency Plan, and its lower-tier implementing procedures, had not resulted in any reduction in effectiveness of the Plan, and that the revised Plan continued to meet the standards in 50.47(b) and the requirements of 10 CFR 50 Appendix E.

The inspectors performed an in-office review of all EAL and Emergency Plan changes submitted by Exelon as required by 10 CFR 50.54(q)(5), including the changes to lower-tier emergency plan implementing procedures, to evaluate for any potential reductions in effectiveness of the Emergency Plan. This review by the inspectors was not documented in an NRC Safety Evaluation Report and does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety. The requirements in 10 CFR 50.54(q) were used as reference criteria.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06 – 1 sample)

.1 Training Observations

a. Inspection Scope

The inspectors observed a simulator training evolution for Oyster Creek Nuclear Generating Station licensed operators on October 21, 2014, which required emergency plan implementation by an operations crew. Exelon planned for this evolution to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that Exelon evaluators noted the same issues and entered them into the corrective action program.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Public Radiation Safety and Occupational Radiation Safety

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01 – 1 sample)

a. Inspection Scope

During the period of November 17 – 20, 2014, the inspectors reviewed Exelon's performance in assessing the radiological hazards and exposure control in the workplace. The inspectors used the requirements in 10 CFR 20, RG 8.38, technical specifications, and the procedures required by technical specifications as criteria for determining compliance.

Radiological Hazard Assessment

There were no samples available to observe air sampling of, or work in potential airborne radioactivity areas during the inspection period.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with radiation monitoring and exposure control were being identified and resolved appropriately in the corrective action program. The inspectors assessed Exelon's process for applying radiation protection operating experience to their facility.

b. Findings

No findings were identified.

2RS2 Occupational ALARA Planning and Controls (71124.02 – 1 sample)

a. Inspection Scope

During the period of November 17 – 20, 2014, the inspectors reviewed performance with respect to maintaining occupational individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements in 10 CFR Part 20, RG 8.8, RG 8.10, technical specifications, and procedures required by technical specifications as criteria for determining compliance.

Radiological Work Planning

The inspectors determined whether post-job reviews were conducted to identify lessons learned. If problems were identified, the inspectors verified that worker suggestions for improving dose and contamination reduction techniques were entered into Exelon's corrective action program. The inspectors compared the results achieved (dose rate reductions, actual dose) with the intended dose established in ALARA planning for the following refueling outage 25 work activities: Drywell under vessel activities, drywell scaffolding, and drywell in-service inspection activities. The inspectors compared the person-hour estimates provided by maintenance planning and other groups to the actual person-hours for these work activities, and evaluated the accuracy of the time estimates.

The inspectors assessed the reasons for any inconsistencies between intended and actual work activity doses.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with ALARA planning and controls are being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's corrective action program.

b. Findings

No findings were identified.

2RS5 Radiation Monitoring Instrumentation (71124.05)

a. Inspection Scope

During the period of October 20 – 24, 2014, the inspectors reviewed Exelon's performance in assuring the accuracy and operability of radiation monitoring instruments used for radioactive effluent monitoring and sample measurements. The inspectors used the requirements in 10 CFR Part 20; 10 CFR 50, Appendix I; technical specifications; Offsite Dose Calculation Manual (ODCM); applicable industry standards; and procedures required by technical specifications as criteria for determining compliance.

During the period of November 17 – 20, 2014, the inspectors reviewed Exelon's performance in assuring the accuracy and operability of radiation monitoring instruments used for effluent monitoring and analyses. The inspectors used the requirements in 10 CFR Part 20; 10 CFR 50, Appendix I; technical specifications; ODCM; applicable industry standards; and procedures required by technical specifications as criteria for determining compliance.

Inspection Planning

The inspectors conducted in-office preparation and review of the following documents: 2012 and 2013 Oyster Creek radioactive effluent and environmental annual reports; UFSAR; and ODCM.

Walkdowns and Observations

The inspectors reviewed the following:

- Observed source checks for several portable survey instruments, including: MGP Telepole, Eberline ASP-1/NRD Neutron Meter, Ludlum 1000 alpha beta smear counter and Bicron Micro R meter portable survey instruments
- Walked down radioactive effluent/process monitor configurations
- Walked down five area radiation monitors and six continuous air monitors

Laboratory Instrumentation

The inspectors reviewed the following:

- Performance and calibration checks of selected laboratory analytical instruments (gamma spectroscopy, alpha/beta counter, liquid scintillation)
- Corrective actions taken in response to indications of degraded instrument performance

Whole Body Counter

The inspectors reviewed the following:

- Calibration records for the whole body counter and the methods and sources used to perform functional checks
- Anomalous results or other indications of instrument performance problems

Post-Accident Monitoring Instrumentation

The inspectors reviewed Exelon's capabilities to collect post-accident effluent samples.

Portal Monitors, Personnel Contamination Monitors, and Small Article Monitors

The inspectors selected two of each type of these instruments and reviewed the following:

- Alarm set-point values
- Calibration method and documentation of each instrument selected

Portable Survey Instruments, Area Radiation Monitors, Electronic Dosimetry, and Air Samplers/Continuous Air Monitors

The inspectors reviewed the following:

- Calibration documentation for at least one of each type of portable instrument in use.
- Detector measurement geometry and calibration methods used
- Five portable survey instruments that did not meet acceptance criteria during calibration or source checks and the corrective actions taken

Instrument Calibrator

The inspectors reviewed the following:

- Calibration measurements made of the instrument calibrator using an ion chamber/electrometer
- Instrument calibrator calibration traceability to the National Institute of Science and Technology

Problem Identification and Resolution

The inspectors evaluated whether problems associated with the effluent radiation monitoring systems were being identified at an appropriate threshold and were properly addressed for resolution in the licensee corrective action program.

b. Findings

No findings were identified.

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06)

a. Inspection Scope

During the period of November 17 – 20, 2014, the inspectors reviewed Exelon's performance in treatment, monitoring and control of effluent releases including adequacy of public dose calculations and projections. The inspectors used the requirements in 10 CFR Part 20; 10 CFR 50, Appendix I; technical specifications; ODCM; applicable industry standards; and procedures required by technical specifications as criteria for determining compliance.

ODCM and UFSAR Reviews

The inspectors reviewed the UFSAR changes associated with effluent monitoring and control and changes to the ODCM including technical justifications.

Problem Identification and Resolution

The inspectors evaluated whether problems associated with the effluent monitoring and control program were being identified at an appropriate threshold and were properly addressed for resolution in the licensee corrective action program.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index (5 samples)

a. Inspection Scope

The inspectors reviewed Exelon's submittal of the Mitigating Systems Performance Index for the following systems for the period of October 1, 2013 through September 30, 2014:

- Emergency Alternating Current (AC) Power System
- High Pressure Injection System
- Heat Removal – Isolation Condensers

- Residual Heat Removal (RHR) – Containment Spray
- Cooling Water System

To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator (PI) Guideline," Revision 7. The inspectors also reviewed Exelon's operator narrative logs, condition reports, mitigating systems performance index derivation reports, event reports, and NRC integrated inspection reports to validate the accuracy of the submittals.

b. Findings

No findings were identified.

.2 Occupational Exposure Control Effectiveness (1 sample)

a. Inspection Scope

During the period of November 17 – 20, 2014, the inspectors sampled licensee submittals for the occupational exposure control effectiveness PI for the period from the fourth quarter 2013 through the third quarter 2014. The inspectors used PI definitions and guidance contained in the NEI Document 99-02, Revision 7, to determine the accuracy of the PI data reported.

The inspectors reviewed electronic personal dosimetry accumulated dose alarms, dose reports, and dose assignments for any intakes that occurred during the time period reviewed to determine if there were any additional unreported PI occurrences.

b. Findings

No findings were identified.

.3 Radiological Effluent Technical Specification/ODCM Radiological Effluent Occurrences (1 sample)

a. Inspection Scope

During the period of November 17 – 20, 2014, the inspectors sampled licensee submittals for the radiological effluent technical specification/ODCM radiological effluent occurrences PI for the period from the fourth quarter 2013 through the third quarter 2014. The inspectors used PI definitions and guidance contained in the NEI Document 99-02, Revision 7, to determine the accuracy of the PI data reported during this period.

The inspectors reviewed the corrective action report database for any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors also reviewed gaseous and liquid effluent summary data and the results of associated offsite dose calculations for the time period reviewed.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 – 5 samples)

.1 Routine Review of Problem Identification and Resolution Activities

a. Inspection Scope

As required by Inspection Procedure 71152, “Problem Identification and Resolution,” the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that Exelon entered issues into the corrective action program at an appropriate threshold, gave adequate attention to timely corrective actions, and identified and addressed adverse trends. 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 corrective action program and periodically attended condition report screening meetings.

b. Findings

No findings were identified.

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a semi-annual review of site issues, as required by Inspection Procedure 71152, “Problem Identification and Resolution,” to identify trends that might indicate the existence of more significant safety issues. The inspectors performed a focused review on issue reports that potentially could be screened as Maintenance Rule Functional Failures to determine if there were trends or precursors that could be identified and to review the effectiveness of corrective actions. The inspectors reviewed issue reports generated during the second and third quarter of 2014 to determine if the issue reports were screened and investigated in accordance with Exelon procedures. The inspectors also reviewed issue reports for the third and fourth quarters of 2013 to assess if trends exist in various subject areas (equipment problems, human performance issues, etc.), as well as individual issues identified during the NRC daily condition report review.

b. Findings and Observations

No findings were identified.

The inspectors noted that Oyster Creek is generating issue reports at an appropriate rate and threshold. No discernable new trends were identified.

The inspectors noted that issues were generally screened appropriately and investigations were assigned in accordance with Exelon corrective action program procedures and in most instances the issue reports were appropriately and timely screened for Maintenance Rule Functional Failures.

The inspectors noted that issue reports pertaining to the acoustic and thermocouple monitoring systems for the electromatic relief valves were not properly screened and evaluated in some cases in accordance with their condition based monitoring program. This resulted in the Post Accident Monitoring system requiring an (a)(1) evaluation in accordance with the Maintenance Rule Program. The inspectors independently screened this issue as minor in accordance with IMC 0612 because the system never lost its ability to perform its function.

The inspectors also noted that there were a higher number of issue reports that were identified by oversight organizations. The issues identified by the oversight organizations tended to be more insightful than those that were self-identified. They also had the tendency to identify issues at a lower threshold. The inspectors discussed with plant management that more issue reports could be generated and they could be more self-critical when reviewing their performance at the worker and first line levels.

.3 Annual Sample: Review of the Operator Workaround Program

a. Inspection Scope

The inspectors reviewed the cumulative effects of the existing operator workarounds, operator burdens, existing operator aids and disabled alarms, and open main control room deficiencies to identify any effect on emergency operating procedure operator actions, and any impact on possible initiating events and mitigating systems. The inspectors evaluated whether station personnel had identified, assessed, and reviewed operator workarounds as specified in Exelon procedure OP-AA-102-103, "Operator Work-Around Program."

The inspectors reviewed Exelon's process to identify, prioritize and resolve main control room distractions to minimize operator burdens. The inspectors reviewed the system used to track these operator workarounds and recent Exelon self-assessments of the program. The inspectors also toured the control room and discussed the current operator workarounds with the operators to ensure the items were being addressed on a schedule consistent with their relative safety significance.

b. Findings and Observations

No findings were identified.

The inspectors determined that the issues reviewed did not adversely affect the capability of the operators to implement abnormal or emergency operating procedures. The inspectors also verified that Exelon entered operator workarounds and burdens into the corrective action program at an appropriate threshold and planned or implemented corrective actions commensurate with their safety significance.

.4 Annual Sample: EDG Cooling Fan Shaft Failure

a. Inspection Scope

The inspectors performed an in-depth review of Exelon's apparent cause evaluation and corrective actions associated with IR 1686101, "EDG No. 2 Fan Belt Came Off Causing

High Temp Alarm." Specifically, the EDG No. 2 cooling fan upper shaft sheared into two pieces during a bi-weekly surveillance test, which resulted in a loss of cooling and subsequent inoperability of EDG No. 2.

The inspectors assessed Exelon's problem identification threshold, cause analyses, extent of condition reviews, compensatory actions, and the prioritization and timeliness of Exelon's corrective actions to determine whether Exelon was appropriately identifying, characterizing, and correcting problems associated with this issue and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to Exelon's corrective action program and the requirements of 10 CFR 50, Appendix B. In addition, the inspectors performed field walkdowns and interviewed engineering personnel to assess the effectiveness of the implemented corrective actions.

b. Observations

The inspectors concluded that Exelon staff conducted an appropriate technical review in sufficient detail to identify the likely causes of the fan shaft failure. Their review included a metallurgical examination performed by a laboratory (Exelon Power Labs) and a fatigue analysis performed by a third party contractor. The inspectors also concluded that Exelon staff identified the extent of condition which was limited to the one redundant EDG unit. Corrective actions included replacement of the failed EDG No. 2 fan shaft, ultrasonic testing of the EDG No. 1 fan shaft for potential degradation, and reducing the level of fan belt tension on both EDG units.

Exelon staff documented in their apparent cause evaluation that the shaft failure occurred via rotational bending fatigue. Based on observations of the fracture surface, Exelon staff determined that cracking initiated at a grooved location in the shaft, which acted as a stress concentration, and cracking propagated by a high-cycle, low-stress fatigue mechanism. Exelon staff further documented that no material defects were observed on the shaft outer surface that would have contributed to the failure initiation. Exelon staff concluded that the apparent cause of the shaft failure was a higher than average stress concentration factor due to a manufacturing deficiency at the grooved location and that the contributing cause was the EDG belt tension setting did not provide adequate margin necessary to address stress risers at the notch in the shaft. These conclusions were reported to the NRC in License Event Report (LER) 2014-003, dated November 11, 2014 (ADAMS accession number ML14325A598).

The inspectors determined Exelon's overall response to the issue was commensurate with the safety significance, was timely, and included appropriate compensatory actions. The inspectors concluded that actions completed to re-evaluate the fan belt tension, revise maintenance procedures to decrease belt tension acceptance criteria, and take action to lower the belt tension on both EDG No. 1 and EDG No. 2 were reasonable to correct the problem and prevent reoccurrence. Action completed to examine the EDG No. 1 shaft by ultrasonic testing was appropriate to determine a crack had not initiated in the shaft at the grooved location (i.e. highest stress area). Exelon staff also initiated a planned corrective action to replace the EDG No. 1 shaft.

Notwithstanding, the inspectors determined that in their review of the EDG maintenance records, Exelon staff missed an opportunity to identify their maintenance staff did not use calibrated measurement and test equipment for the field measurement of EDG cooling fan belt tensions. Specifically, the belt tension meter used to measure fan belt tension from May 2005 to October 2014, was classified as “General Use” measurement and test equipment by Exelon and was not certified or calibrated. In response to inspectors’ questions, Exelon staff had the belt tension meter calibrated on January 7, 2015, and it was found to be within calibration tolerances. Exelon staff entered this issue into their corrective action program (IR 2434265). While this issue represented a violation involving 10 CFR 50, Appendix B, Criterion XII regarding control of measurement and test equipment for safety-related activities, inspectors determined that this issue was minor because no equipment operability or functionality was adversely impacted. In accordance with IMC 0612, "Power Reactor Inspection Reports," the above issue constituted a violation of minor significance that is not subject to enforcement action in accordance with the Enforcement Policy.

c. Findings

Introduction. The inspectors identified a preliminary White finding and associated apparent violation of 10 CFR 50, Appendix B, Criterion III, “Design Control,” because Exelon did not review the suitability of the application of a different maintenance process at Oyster Creek Nuclear Generating Station that was essential to a safety-related function of the EDGs.

Description. On July 28, 2014, EDG No. 2 was operated for its bi-weekly load surveillance test when alarms “EDG 2 ENGINE TEMP HI” and “EDG 2 DISABLE” were received. Following shutdown of the EDG unit, the fan duct access was opened and Exelon staff discovered that the cooling fan upper shaft had sheared into two pieces at the bearing support. Exelon’s immediate corrective actions consisted of replacing the fan shaft, performing ultrasonic testing on the EDG No. 1 fan shaft for extent of condition, and initiating an apparent cause evaluation to investigate and identify the causes of the shaft failure.

Oyster Creek is equipped with two identical EDG units. The function of the EDGs is to provide AC power to the safety-related class 1E busses upon a loss of off-site power. The EDG units are installed in self-contained enclosures inside the EDG vaults and are cooled via radiators in duct compartments configured atop the engine. Cooling air to each engine is drawn into this duct by a large fan. The fan is supported and rotated by a belt-driven shaft (upper shaft) that is, in turn, rotated by a power-takeoff shaft (lower shaft) connected to the engine.

As part of their investigation, Exelon staff sent parts of the shaft section and bearing to Exelon Power Labs for failure analysis and also utilized a vendor to perform a stress analysis on fatigue crack initiation and growth. Exelon Power Labs concluded that the fracture was caused by rotational bending fatigue, and the cracking initiated at the shaft groove diameter transition, which would act as a high stress concentrator. Exelon Power Labs also concluded that no material defects were observed on the shaft outer diameter surface that would have contributed to the initiation of the fatigue failure. Based on the laboratory failure results, Exelon staff analyzed the mechanical loads placed on the fan shaft and determined the crack growth time period. Exelon staff concluded that the potential causes of rotational bending fatigue were: 1) the shaft hub loading exceeded the material properties, or 2) a defect produced a stress riser at the groove location in the shaft. Exelon staff further concluded that the EDG No. 2 could have met its mission time (24 hours) approximately four test cycles (or 42 days) prior to the shaft's failure on July 28, 2014, based on physical evidence preserved in the fracture surface and supporting crack growth calculations.

Exelon staff reported the results of their apparent cause evaluation in LER 2014-003, dated November 11, 2014. Exelon staff concluded that the EDG No. 2 fan shaft likely failed due a higher than average stress concentration factor caused by a manufacturing deficiency in the grooved location on the shaft. Exelon staff further reported that limited detail was available from the shaft manufacturer regarding shaft groove profile, surface finish, and material properties. Exelon staff reported that the increased belt tension was a contributing cause because the increased belt tension did not provide adequate margin to address stress risers at the groove. As part of the corrective actions, Exelon staff performed a technical evaluation to determine the correct belt tension, reduced the fan belt tensions on both EDGs, and revised the acceptance criterion stated in the EDG belt maintenance procedure from 60 Hz to 47.4 Hz. Exelon staff also recommended that fan shaft vibration performance monitoring be implemented in the EDG 24-month inspection.

The inspectors reviewed the apparent cause analysis and supporting failure analysis reports, and performed independent reviews of the shaft stresses and fatigue life based on those stresses. The inspectors determined that, considering the "as found" groove and shaft dimensions, the belt tension acceptance criterion of 60 (+/- 2) Hz specified in Oyster Creek's belt maintenance procedure resulted in a stress greater than the reported fatigue endurance limit of the shaft material (i.e. the fan shaft would no longer operate indefinitely). The inspectors also determined that EDG No. 2 likely operated for a sufficient time at this stress level such that a crack could be initiated in the shaft. Specifically, the fan belt tension corresponding to the acceptance criteria likely caused the fan shaft to accumulate fatigue usage periodically every two years when the fan belt was re-tensioned at a value above its endurance limit. The inspectors noted that the EDG No. 2 fan belt was tensioned between 59 to 61 Hz as recorded in previous work orders.

Furthermore, the inspectors' review of the apparent cause evaluation and associated analyses identified that Exelon staff used a nominal shaft diameter of 3.0 inches in their stress calculations and not the measured shaft diameter of 2.939 inches. The inspectors observed the measured diameter was identified as an input to their analysis, but the nominal shaft diameter was used. The inspectors discussed this observation with Exelon staff and determined that the stress concentration factor utilized in the analysis served as a bounding stress concentration factor for the shaft groove area. Exelon staff further stated that this bounding stress concentration factor would account for small differences in the shaft dimensions. The inspectors determined utilizing the measured diameter in their stress calculations was appropriate for failure analysis of this specific shaft. Using the measured shaft diameter increased the calculated shaft stresses at the analyzed belt tension loads. Considering the stress concentration from the groove (a stress concentration factor of 3 was used in Exelon's evaluation) and measured shaft diameter, the inspectors determined the belt tension acceptance criteria at 60 Hz (i.e. hub load) resulted in a calculated stress greater than the reported endurance limit of the shaft material. The inspectors noted this conclusion differed from information in LER 2014-003 that indicated the hub load at 60 Hz produced stresses in the shaft groove transition of 19.15 kips/inch^2 (ksi), "at or just below the endurance limit of the shaft material."

The inspectors reviewed the EDG maintenance history to evaluate Exelon's performance. Prior to May 2005, Exelon staff followed the instructions in the diesel generator vendor manual for performing maintenance on the diesel cooling system, which included the cooling fan belt. The vendor manual directed tensioning of the belt until it deflected approximately 7/16 inch with an applied force of 10 to 13 pounds. As part of corrective actions from a loose belt issue on EDG No. 1 in 2004, Exelon staff created a new procedure, MA-OC-86103-100, "Diesel Generator Fan Belt Replacement," for performing EDG fan belt maintenance. This new procedure changed the method for tensioning the belt from a standard belt deflection technique to measuring the frequency at which the belt vibrates after being struck with an object. The frequency of the belt corresponds to belt tension. Exelon established an acceptance criterion of 60.6 (+/- 1) Hz; however, there was not a documented or referenced evaluation that described how the frequency acceptance criterion in the new procedure was calculated or whether this frequency was equivalent to the deflection criterion in the vendor manual. The inspectors noted that the belt tension acceptance criteria in procedure MA-OC-86103-100 was subsequently revised to 60 (+/- 2) Hz on April 9, 2008 in Revision 2.

The inspector's determined that Exelon procedure AD-AA-101, "Processing of Procedures," was in effect in 2005 and required a procedure to be validated if the procedure was a new task or significantly altered the methodology previously used. Procedure validation would have verified the procedure could be performed and that the acceptance criteria were adequate. The inspectors identified that this validation step was not performed during the processing of maintenance procedure MA-OC-86103-100 when it was issued in 2005. The inspectors determined procedure AD-AA-101 also required the station qualified reviewer to determine if a cross-disciplinary review was necessary; however, the inspectors identified that a cross-discipline review was not performed by engineering staff during the processing of MA-OC-86103-100, although there was a significant increase in shaft loading from the increased belt tension. The procedure was processed by maintenance department staff only. The inspectors determined that these are two examples where Exelon staff did not implement procedural requirements and are therefore performance deficiencies.

Analysis. The inspectors determined that Exelon's failure to properly review and validate the acceptance criteria of a new EDG belt maintenance process, essential to a safety-related function of the EDGs, in accordance with 10 CFR 50, Appendix B, Criterion III, was a performance deficiency, because it was reasonably within Exelon's ability to foresee and correct and should have been prevented. Specifically, an evaluation would have reasonably considered the stress placed on the fan shaft due to increasing the belt tension and evaluated the margin in the shaft design considering the controls placed on shaft dimensions, material and surface finish. An evaluation, if conducted, would also have likely involved EDG vendor consultation regarding this change.

This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," issued June 19, 2012, the inspectors screened the finding for safety significance and determined that a detailed risk evaluation was required because EDG No. 2 was inoperable for greater than the technical specification allowed outage time. Based upon the detailed risk evaluation, the calculated change in core damage frequency for this issue was 5.1E-6, or low to moderate safety significance (White). The dominant internal core damage sequences involved various losses of offsite power initiating events followed by failure of the remaining 4160 Volt AC emergency bus. The dominant external event core damage sequences involved switchyard fires that contributed to loss of offsite power. The time that the EDG was available before failure was credited in the analysis and afforded operators more time to recover offsite power, which lowered the risk of this issue. Also, diverse make-up sources to the isolation condenser and availability of the Forked River Combustion Turbine Generators helped mitigate the risk. An exposure time of 44 days (42 days plus two days for corrective maintenance) was used for the time the EDG could have met its 24 hour mission time. A detailed analysis is contained in Attachment 1 of this report. This finding does not have an associated cross-cutting aspect because the performance deficiency occurred in 2005 and is not reflective of present performance.

Enforcement. 10 CFR 50, Appendix B, Criterion III, "Design Control," states, in part, that "measures shall be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components," and that "measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program." Contrary to the above, from May 13, 2005, to September 9, 2014, Exelon did not review the suitability of the application of a different maintenance process at Oyster Creek that was essential to a safety-related function of the EDGs. Specifically, Exelon changed the method for tensioning the cooling fan belt on the EDG from measuring belt deflection to belt frequency and did not verify the adequacy of the acceptance criteria stated for the new method. As a result, Exelon did not identify that the specified belt frequency imposed a stress above the fatigue endurance limit of the shaft material, making the EDG cooling fan shaft susceptible to fatigue and failure on July 28, 2014. As a consequence of this design control issue, Exelon also violated Technical Specification 3.7.C, because EDG No. 2 was determined to be inoperable for greater than the technical specification allowed outage time. Exelon's immediate corrective actions included entering the issue into their corrective action program (IR 1686101), replacement of the EDG No. 2 fan shaft, examining the EDG No. 1 fan shaft for extent of condition, and initiating a failure analysis to determine the causes of the broken shaft. This issue is being characterized as an AV in accordance with the NRC's Enforcement Policy, and its final significance will be dispositioned in separate future correspondence. **(AV 05000219/2014005-02, Inadequate Review of Change in Maintenance Process Results in Inoperable Emergency Diesel Generator)**

.5 Annual Sample: Reactivity Management Event

a. Inspection Scope

The inspectors conducted a Problem Identification and Resolution sample for evaluation of corrective actions associated with a reactor re-criticality during plant shutdown activities on July 8, 2014.

The inspectors reviewed and assessed crew operator performance and crew decision making, including adherence to expected roles and responsibilities, the use of command

and control elements associated with reactivity manipulations, the use of procedures, the use of diverse instrumentation to assess plant conditions and overall implementation of operations department and station standards; determined the appropriateness and safety significance of up-ranging on intermediate range monitors (IRM) during this event; determined the appropriateness and safety significance of inserting each SRM individually rather than fully inserting all SRMs over one continuous stroke; reviewed and assessed the effectiveness of Exelon's response to this event and corrective actions taken to date, including overall organizational response, evaluation of the apparent cause, and adequacy of corrective actions; reviewed the adequacy of the preparation by the operations staff for the reactor shutdown including training prior to the evolution and briefings by the operations staff; reviewed the adequacy of operator requalification training as it related to this event; assessed the decision making and actions taken by the operators during the reactor shutdown to determine if there are any implications related to safety culture; reviewed the adequacy of the simulator to model the behavior of the current reactor core during shutdown activities and the current adequacy of the simulator for use in reactor shutdown training; evaluated Exelon's application of pertinent industry operating experience and assessed the effectiveness of any actions taken in response to the operating experience.

b. Findings and Observations

.1 Inadequate Plant Shutdown Procedure

Introduction. The inspectors identified a Green NCV of Technical Specification 6.8.1(a), "Procedures and Programs," because Exelon's Plant Shutdown procedure 203 was not adequately established and maintained. Specifically, the procedure was not adequate in that it did not contain precautions concerning rod insertion when reactor power is below the point of adding heat; operational limitations on plant cooldown when power is below the point of adding heat and contingency actions for re-criticality during shutdown.

Description. On July 8, 2014, while performing a technical specification required plant shutdown to address electromatic relief valve operability concerns, licensed operators allowed the reactor to regain criticality twice when power was below the point of adding heat.

The plant shutdown was being performed in accordance with Procedure 203, "Plant Shutdown," utilizing a manual control rod insertion sequence which results in all control rods completely inserted, ("soft shutdown") that is, without inserting a reactor scram.

As compared to a normal shutdown with a reactor scram inserted from approximately 10 percent power, a soft shutdown requires additional time for complete manual insertion of all control rods. Due to delays experienced during shutdown and the additional time for rod insertion, positive reactivity effects from xenon (xenon was decaying vice rising), and reactor cooldown associated with existing steam loads, become more significant when reactor power is reduced below the point of adding heat.

The positive reactivity effects of xenon and cooldown must be countered by the negative reactivity contributed by control rod insertion. The inspectors noted that Procedure 203 did not contain any precautionary guidance to alert the operators concerning the need to prioritize control rod insertion during soft shutdown. Additionally, the inspectors noted that Procedure 203 did not contain any amplifying guidance as to the necessity to limit reactor cooldown during soft shutdown.

Operators had proceeded with rod insertion and the reactor shutdown sufficiently such that power was below the point of adding heat and the reactor was subsequently subcritical. When the operators stopped control rod insertion during the shutdown to partially insert individual SRMs, the reactor regained criticality due to the positive reactivity being added by the xenon decay and reactor cooldown. The operators ranged IRMs up to keep power visible on range and recommenced rod insertion, which turned power downward and made the reactor subcritical. Operators again stopped control rod insertion to further insert SRMs, and again the reactor regained criticality due to positive reactivity effects. Operators were directed to continuously insert control rods by the unit supervisor, the reactor was made subcritical and the shutdown proceeded until all control rods were fully inserted. The inspectors noted that Procedure 203 did not contain any contingency actions for situations where the reactor regains criticality during shutdown.

Analysis. The inspectors determined that not maintaining an adequate plant shutdown procedure in accordance with Technical Specification 6.8.1 is a performance deficiency that was within Exelon's ability to foresee and correct. The inspectors determined this finding was more than minor because the finding affected the procedure quality attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the reliability and capability of systems that respond to initiating events. Specifically, the plant shutdown procedure did not contain precautions to continuously insert control rods when reactor power is less than the point of adding heat, did not define operational considerations for limiting reactor cooldown and did not contain contingency actions for return to criticality during shutdown.

The inspectors screened this issue using IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power." The inspectors answered "yes" to question C.3 because the finding resulted in a mismanagement of reactivity by operators in that they demonstrated an inability to anticipate and control changes in reactivity during plant operations. As such, inspectors assessed this finding using IMC 0609 Appendix M, "Significance Determination Process Using Qualitative Criteria." A senior reactor analyst performed the bounding analysis required by Appendix M. In this analysis, the senior reactor analyst made conservative assumptions that a transient had occurred in which the operators would have always failed to manually scram the reactor, and the reactor protective system had electrical failures which made it less reliable. This conservative analysis yielded a change in core damage frequency of 8.0E-7 and the finding was determined to be of very low safety significance (Green).

This finding has a cross-cutting aspect in the area of Human Performance, Documentation, because Exelon did not ensure that the shutdown procedure contained adequate controls for soft shutdown. [H.7]

Enforcement. Technical Specification 6.8.1a, "Procedures and Programs," states, in part, that written procedures shall be established, implemented, and maintained as recommended in Appendix A of Regulatory Guide 1.33, February 1978. Regulatory Guide 1.33, Appendix A discusses general plant operating procedures including Plant Shutdown to Hot Standby. Contrary to the above, prior to July 8, 2014, Exelon did not properly maintain procedure 203, Plant Shutdown to include precautions, clarifications, and contingency action for recriticality during soft shutdown. Because this violation was of very low safety significance and it was entered into Exelon's corrective action program as IR 2412093, this violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy. **(NCV 05000219/201405-03, Plant Shutdown Procedure Was Inadequate For Soft Shutdown)**

.2 Procedure Use and Adherence

Introduction. The inspectors identified a Green NCV of Technical Specification 6.8.1(a), "Procedures and Programs," because Oyster Creek operators did not adequately implement procedures when performing a plant shutdown. Specifically, the operators did not ensure that all personnel on shift had received Just in Time Training for their role in the shutdown, operators did not perform a reactivity Heightened Level Awareness brief for the shutdown, and did not insert SRMs in accordance with procedure. These issues contributed to two unanticipated criticalities during the shutdown.

Description. On July 8, 2014, prior to, and during the course of a technical specification required reactor shutdown, Oyster Creek licensed reactor operators did not implement written procedures.

Procedure 203, "Plant Shutdown," Revision 75, Step 3.9, states, in part, that operators are to "Perform a Reactivity Heightened Level Awareness Briefing for Shutdown in accordance with Attachment 203-13." Attachment 2013-13, "Reactivity Heightened Level Awareness Briefing for Shutdown," contains additional discussion topics for a "Soft Shutdown" without a Scram and includes recommended discussion points during the Heightened Level Awareness brief to include "Potential for Re-Criticality due to Reactor Cooldown, Including Instrumentation to Monitor, and the Indications of Impending Re-Criticality (IRM Slope Changes)." The relieving shift on the morning of July 8, 2014, did not perform a reactivity Heightened Level Awareness brief covering the topics of Attachment 203-13, as indicated during personnel interviews.

Procedure 203, "Plant Shutdown," Revision 75, Step 3.5, states in part that, "If shift turnover occurs during the shutdown, then all relieving personnel have had Just-in-Time-Training for their role." However, the licensed operator-at-the-controls during the unanticipated criticalities did not attend the provided Just-in-Time-Training on July 7, 2014, prior to relieving the watch on July 8, 2014, as indicated by the training attendance sheet.

Procedure 401.3, "Operation of Nuclear Instrumentation SRM Channel During and After Shutdown," Revision 11, Step 5.4, states that when count rate is approximately 10^3 counts per second (cps), "Fully insert SRM chambers by placing the IRM-SRM DRIVE CONTROL switch to IN." However, upon reaching this step, licensed operators incrementally inserted the SRM detectors into the reactor causing a delay in rod insertion when operating at low power levels.

Analysis. The inspectors determined that the failure of personnel to implement procedures during the plant shutdown, in accordance with Technical Specification 6.8.1, was a performance deficiency that was reasonably within Exelon's ability to foresee and prevent. The finding is more than minor because it was associated with the Human Performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the operator failure to implement procedures during the plant shutdown contributed to two unanticipated returns to criticality which required operator action to mitigate.

The inspectors screened this issue using IMC 0609.04, "Initial Characterization of Findings," and Exhibit 2 of IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power." The inspectors answered "yes" to question C.3 because the finding resulted in a mismanagement of reactivity by operators in that they demonstrated an inability to anticipate and control changes in reactivity during plant operations. As such, inspectors assessed this finding using IMC 0609 Appendix M, "Significance Determination Process Using Qualitative Criteria." A senior reactor analyst performed the bounding analysis required by Appendix M. In this analysis, the senior reactor analyst made conservative assumptions that a transient had occurred in which the operators would have always failed to manually scram the reactor, and the reactor protective system had electrical failures which made it less reliable. This conservative analysis yielded a change in core damage frequency of 8.0E-7 and the finding was determined to be of very low safety significance (Green).

This finding has a cross-cutting aspect in the area of Human Performance, Procedure Adherence, because licensed operators did not implement processes, procedures and work instructions during the plant shutdown. [H.8]

Enforcement. Technical Specification 6.8.1(a), "Procedures and Programs," states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Regulatory Guide 1.33, Appendix A requires that safety-related activities listed therein be covered by written procedures. Contrary to the above, on July 8, 2014, the licensee failed to properly implement safety-related procedures related to Regulatory Guide 1.33, Appendix A, Paragraph 1, "Administrative Procedures;" Paragraph 2, "General Plant Operating Procedures;" and Paragraph 4, "Procedures for Startup, Operation, and Shutdown of Safety-Related BWR Systems." Because this violation was of very low safety significance and it was entered into Exelon's corrective action program as IR 2412093 this violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy. **(NCV 05000219/201405-04, Procedures Not Implemented During Plant Shutdown)**

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

.1 Plant Events

a. Inspection Scope

For the plant events listed below, the inspectors reviewed and/or observed plant parameters, reviewed personnel performance, and evaluated performance of mitigating systems. The inspectors communicated the plant events to appropriate regional personnel, and compared the event details with criteria contained in IMC 0309, "Reactive Inspection Decision Basis for Reactors," for consideration of potential reactive inspection activities. As applicable, the inspectors verified that Exelon made appropriate emergency classification assessments and properly reported the event in accordance with 10 CFR Parts 50.72 and 50.73. The inspectors reviewed Exelon's follow-up actions related to the events to assure that Exelon implemented appropriate corrective actions commensurate with their safety significance.

- Reactor scram during automatic voltage regulator troubleshooting on October 12, 2014

b. Findings

No findings were identified.

.2 (Closed) Exelon Event Report (LER) 05000219/2013-005-01: Reactor Protection System Actuation with the Reactor in Hot Shutdown

On December 17, 2013, while the plant was shut down, the plant experienced a reactor scram when taking the mode switch from refuel position to shutdown position. The jumpers required to prevent a full scram for the mode switch change were not installed as required by procedure. The reactor protection system actuation was a result of the reactor mode switch being placed from the refuel position to the shutdown position without the scram bypass jumpers installed.

The root cause determined that an invalidated assumption by the supervisors resulted in a reactor scram while shut down. The reactor was subcritical with all rods inserted at the time of the reactor protection system actuation, therefore this is considered minor per IMC 0612. Inspectors completed a problem identification and resolution sample to review the details of the event in NRC inspection report 05000219/2014003, Section 4OA2, “Annual Sample: Operator Actions during a Reactor Scram on December 14, 2013 and Subsequent Startup Reactor Scram Signal.” No findings were identified in this review. The inspectors did not identify any violations or new issues during the review of the LER. This LER is closed.

.3 (Closed) Exelon Event Report (LER) 05000219/2014-003-00: Technical Specification Prohibited Condition Caused by EDG Inoperable for Greater than Allowed Outage Time

The inspectors reviewed Exelon's actions and reportability criteria associated with LER 05000219/2014-003-00, which was submitted to the NRC on November 11, 2014 (ML14325A598). On July 28, 2014, EDG No. 2 failed during its bi-weekly load surveillance test. The cause of the failure was determined to be rotational bending fatigue. Exelon’s immediate corrective actions consisted of replacing the fan shaft, performing ultrasonic testing on the EDG No. 1 fan shaft for extent of condition, and performing an apparent cause evaluation. The apparent cause evaluation concluded that the EDG was inoperable for approximately 43 days. The inspectors determined that Exelon violated Technical Specification 3.7.C, because EDG No. 2 was determined to be inoperable for greater than the technical specification allowed outage time of 7 days. However, this violation constitutes an additional example of violation AV 05000219/2014005-02, which is described section 4OA2.4.c of this report, and is not being cited individually. The inspectors did not identify any additional findings or violations of NRC requirements during the review of the LER. This LER is closed.

.4 (Closed) Exelon Event Report (LER) 05000219/2014-004-00: Local Leak Rate Test Results in Excess of Technical Specifications

On September 18, 2014, during the 1R25 refueling outage with the reactor in cold shutdown, Exelon discovered the as-found local leak rate test on main steam isolation valve V-1-8, did not meet the acceptance criteria of technical specification 4.5.D.2, "Primary Containment Leak Rate." Specifically, the as-found leak rate for V-1-8 was 16 standard cubic feet per hour (SCFH) which exceed the technical specification acceptance criteria of 11.9 SCFH at a test pressure of 20 psid. The safety significance of the issue is considered minimal due to V-1-8 being installed in series with a second main steam isolation valve (V-1-10) in the affected steam header, which did meet the technical specification acceptance criteria and provides adequate margin between the projected offsite dose and 10 CFR 100 guidelines.

Exelon determined the cause of the failure to be material wear on the poppet and valve seat. The valve was repaired during 1R25 and successfully passed the local leak rate test.

The inspectors determined that the reported technical specification violation was minor, as it was not a precursor to a significant event, did not have the potential to lead to a more significant safety concern, did not relate to a performance indicator that would have exceeded a threshold, and did not adversely affect any of the cornerstone objectives. The inspectors did not identify any new issues during the review of the LER. This LER is closed.

4OA6 Meetings, Including Exit

On January 29, 2015, the inspectors presented the inspection results to Mr. G. Stathes, Site Vice President, and other members of the Oyster Creek Nuclear Generating Station staff. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report.

ATTACHMENT 1: Detailed Risk Evaluation: Failure of EDG No. 2 Fan Shaft
ATTACHMENT 2: Supplementary Information

ATTACHMENT 1: DETAILED RISK SIGNIFICANCE EVALUATION
Oyster Creek Nuclear Generating Station
Failure of Emergency Diesel Generator (EDG) 2 Fan Shaft

Conclusion:

The overall change in core damage frequency for the performance deficiency was 5.1E-6/year (White).

Assumptions:

1. The fan shaft on EDG No. 2 failed due to rotational bending fatigue on July 28, 2014. The analyst assumed that the crack in the fan shaft initiated and propagated only during times that the diesel generator was running during its last 3 surveillance runs. This assumption was based on the fact that rotational bending fatigue would only propagate when the engine is started and run. Prior to that, the analyst assumed the shaft would have met its 24 hour mission time. There was no assumption of accelerated degradation associated with diesel starts or any degradation while the unit was in standby. The analyst assumed that the failure was a deterministic outcome set to occur after the specific number of operating hours which followed the completion of surveillance testing on June 16, 2014.

   After each biweekly run, the EDG's are run for 15 minutes at half speed. The analyst treated this idle time as 7.5 minutes of full speed run time to properly correlate this time to the appropriate number of cycles. This assumption was made because by running the EDG at half speed the number of fatigue cycles is cut in half. The table below lists the run history of EDG No. 2, with idle times included, to develop an adjusted full speed run time equivalent undergoing fatigue.

Date	Run Time (in hours)	Idle time (half-speed) (in hours)	Adjusted time full-speed run time equivalent (in hours)	Cumulative full-speed equivalent time backwards from failure (in hours)
June 16, 2014	1.189	0.25	1.314	5.69
June 30, 2014	1.467	0.25	1.592	4.38
July 16, 2014	1.311	0.25	1.436	2.79
July 28, 2014	1.351	Shaft failure	1.351	1.35

   For example, based on the data provided in the above table , on June 30, 2014, the EDG was run for 1.467 hours at full speed and then idled at half speed for 0.25 hours. Therefore the shaft accrued 1.592 hours of equivalent full speed run time to contribute to failure of the shaft. Adding in the times after June 30, the EDG would have started on a postulated demand and would have been able to run for 4.38 hours before shaft failure.

   Additionally, the analyst assumed the EDG could not operate without the fan. The analyst assumed that EDG No. 2 would have run for a short period of time as engine temperatures rose to the point of actuating high temperature annunciators. The analyst assumed that operators would then secure the EDG or the EDG would fail soon thereafter. This time was assumed to be 15 minutes and was added to the time the EDG fan shaft would fail for determining the total time the EDG would be available. The analyst grouped, or binned, short runs within one day of each other to simplify the binning process. The bins of the run availability times and with the added 15 minutes are presented in the table below:

Bin Number	Time period	Number of days in bin	EDG run time available
1	July 16 – 28	12	1.6 hours
2	June 30 – July 16	16	3.0 hours
3	June 16 – 30	14	4.6 hours

For example, the analyst assumed that EDG No. 2 would have run for 1.6 hours if demanded, during the 12 day period from July 16 to July 28, 2014. Next, EDG No. 2 would have run for 3.0 hours, if demanded, during the 16 day period from June 30 to July 16, 2014.

Before June 16, 2013, the analyst assumed that the fan shaft for EDG No. 2 would have met its 24 hour mission time assumed in the Standardized Plant Analysis Risk (SPAR) model. Therefore, prior to this date no additional risk impact was assumed.

2. The shaft took 41.75 hours (from 5:10 a.m. on July 28 to 11:00 p.m. on July 29) to replace and return to service. The EDG was assumed to have been unavailable during this repair time. Also from this, the EDG No. 2 was assumed to be non-recoverable within the mission time used for the EDG in the SPAR model. This made the total exposure time was from June 16, 2014, to July 29, 2014, or 44 days.

3. Common cause vulnerabilities for EDG No. 1 existed. The belt for the fan shaft for EDG No. 1 was covered by the same procedural tightening specifications. The fan shaft was of similar design, construction, and manufacture. Therefore, the analyst modeled the failure by setting Basic Event EPS-DGN-FR-DG2, "Diesel Generator DG2 Fails to Run," to TRUE in the SPAR model.

4. The station began shutting down on July 7 due to electromagnetic relief valve concerns and experienced a reactor scram due to lowering condenser vacuum on July 11, 2014. During these shutdown periods, the plant was placed on shutdown cooling. The analyst assumed this time was not significant and assumed all of the risk was at-power

The Oyster Creek SPAR model, Revision 8.22, dated May 20, 2014, was used in the analysis. A cutset truncation of 1.0E-13 was used. Average test and maintenance was assumed.

Internal Events Analysis:

A. Risk Estimate for the 42-hour Repair Time period on July 28 through July 29, 2014:

During this 42-hour period, the analyst assumed that EDG No. 2 was completely unavailable as it was being repaired. The result was a conditional core damage probability of 1.52E-7 for the 61-hour period and an annualized core damage frequency (CDF) of 1.52E-7/year.

B. Risk Estimate for the 12-day period between July 16 and July 28, 2014:

During this exposure period, EDG No. 2 was assumed to have been capable of running for 1.6 hours. The loss of offsite power (LOOP) frequencies used in the analysis were adjusted to reflect the situation that only LOOP's with durations greater than 1.6 hours would result in a risk increase attributable to the fan shaft failure. The analyst used the 1.5 hour values from the SPAR model to approximate 1.6 hours.

The base LOOP frequencies from the SPAR model are listed in the second column of the table below. The analyst adjusted these base values by multiplying them by the respective 1.5-hour non-recovery probabilities of offsite power (in the third column) to obtain the frequency of each type of LOOP that was not recovered in 1.5 hours (in the fourth column).

LOOP Type	**Base Frequency**	**Offsite power non-recovery probability for 1.5 hours**	**Adjusted LOOP non-recovery frequency**
Grid Centered (GC)	1.22E-02/year	0.5034	6.14E-03/year
Switchyard Centered (SC)	1.04E-02/year	0.2920	3.04E-03/year
Plant Centered (PC)	1.93E-03/year	0.2341	4.52E-04/year
Weather Related (WR)	3.91E-03/year	0.6136	2.40E-03/year

In this bin, time of t=0 needed to be reset to 1.5 hours following the LOOP event for the recovery factors for offsite power. In the SPAR model, recovery times for offsite power are set at the intervals of 30 minutes, 1 hour, 4 hours, and 10 hours. For instance, in 1-hour sequences for recovery of offsite power in SPAR, the basic event for non-recovery of offsite power should be adjusted to the non-recovery at 2.5 hours, given that, recovery has failed at 1.5 hours after the LOOP began.

Also, an adjustment to account for the diminishment of decay heat must be considered. This is because the magnitude of decay heat following shutdown is less than in the early moments following a reactor trip, and the timing of core damage sequences is affected by this fact. The analyst determined that the average decay heat level in the first 30 minutes is approximately two times the average level that exists 3 to 4 hours following shutdown. Therefore, baseline 30-minute SPAR model sequences, which essentially, account for boil-off to fuel un-covering, were further adjusted to 1-hour sequences.

The 1-hour sequences were further changed to 1.5-hour sequences. The analyst determined that decay heat rates leveled out quickly following shutdown and could find no basis for adjusting the times associated with the 4 and 10-hour sequences. These decay heat adjustments were used for this bin and all following bins.

The following table presents the adjusted offsite power non-recovery factors for the event times that are relevant in the SPAR core damage cutsets:

SPAR recovery time for specific LOOP	Adjustment for decay heat diminishing	Time adjustment for 1.5 hours of run time available	Adjusted LOOP non-recovery frequency for 1.5 hours (/year)	SPAR base offsite power non-recovery at 1.5 hours adjusted to Column 3 times	Modified SPAR non-recovery
30 minute Grid Centered	1 hour	2.5 hour	6.14E-03	0.320	0.636
30 minute Switchyard Centered	1 hour	2.5 hour	3.04E-03	0.182	0.623
30 minute Plant Centered	1 hour	2.5 hour	4.52E-04	0.144	0.615
30 minute Weather Related	1 hour	2.5 hour	2.40E-03	0.520	0.848
1 hour Grid Centered	1.5 hours	3 hour	6.14E-03	0.250	0.496
1 hour Switchyard Centered	1.5 hours	3 hour	3.04E-03	0.145	0.498
1 hour Plant Centered	1.5 hours	3 hour	4.52E-04	0.112	0.477
1 hour Weather Related	1.5 hours	3 hour	2.40E-03	0.480	0.782
4 hour Grid Centered	4 hour	5.5 hours	6.14E-03	0.087	0.173
4 hour Switchyard Centered	4 hour	5.5 hours	3.04E-03	0.059	0.201
4 hour Plant Centered	4 hour	5.5 hours	4.52E-04	0.044	0.187
4 hour Weather Related	4 hour	5.5 hours	2.40E-03	0.349	0.568
10 hour Grid Centered	10 hour	11.5 hours	6.14E-03	0.020	0.041
10 hour Switchyard Centered	10 hour	11.5 hours	3.04E-03	0.019	0.065
10 hour Plant Centered	10 hour	11.5 hours	4.52E-04	0.014	0.059
10 hour Weather Related	10 hour	11.5 hours	2.40E-03	0.233	0.380

The results of this bin of the analysis yielded a CDF of 3.49E-5/year for this bin. When the base case risk (1.25E-5/year) was subtracted from the bin CDF value and applied to a 12 day time period, the core damage probability of 7.36E-7 results. This was annualized to obtain a bin CDF of 7.36E-7/year.

C. <u>Risk Estimate for the 16-day period between June 30 and July 16, 2014</u>:

During this exposure period, EDG No. 2 was assumed to have been capable of running for 3.0 hours. The LOOP frequencies were adjusted to reflect the situation that only LOOPs with durations greater than 3 hours would result in a risk increase attributable to the fan shaft failure.

LOOP Type	Base Frequency	Offsite power non-recovery probability for 1.5 hours	Adjusted LOOP non-recovery frequency
Grid Centered (GC)	1.22E-02/year	0.250	3.05E-03/year
Switchyard Centered (SC)	1.04E-02/year	0.145	1.51E-03/year
Plant Centered (PC)	1.93E-03/year	0.112	2.16E-04/year
Weather Related (WR)	3.91E-03/year	0.480	1.88E-03/year

The methodology was repeated from the 1.5 hour bin. Time of t=0 needed to be reset to 3.0 hours following the LOOP event for the recovery factors for offsite power. Also, the same adjustments to account for the diminishment of decay heat were applied.

The following table presents the adjusted offsite power non-recovery factors for the event times that are relevant in the SPAR core damage cutsets:

SPAR recovery time for specific LOOP	Adjustment for decay heat diminishing	Time adjustment for 3.0 hours of run time available	Adjusted LOOP non-recovery frequency for 1.5 hours (/year)	SPAR base offsite power non-recovery at 1.5 hours adjusted to Column 3 times	Modified SPAR non-recovery
30 minute Grid Centered	1 hour	4 hour	3.05E-03	0.169	0.675
30 minute Switchyard Centered	1 hour	4 hour	1.51E-03	0.102	0.705
30 minute Plant Centered	1 hour	4 hour	2.16E-04	0.078	0.694
30 minute Weather Related	1 hour	4 hour	1.88E-03	0.4244	0.884
1 hour Grid Centered	1.5 hours	4.5 hour	3.05E-03	0.144	0.577
1 hour Switchyard Centered	1.5 hours	4.5 hour	1.51E-03	0.089	0.613
1 hour Plant Centered	1.5 hours	4.5 hour	2.16E-04	0.067	0.600
1 hour Weather Related	1.5 hours	4.5 hour	1.88E-03	0.403	0.840
4 hour Grid Centered	4 hour	7 hours	3.05E-03	0.065	0.261
4 hour Switchyard Centered	4 hour	7 hours	1.51E-03	0.047	0.320
4 hour Plant Centered	4 hour	7 hours	2.16E-04	0.034	0.308
4 hour Weather Related	4 hour	7 hours	1.88E-03	0.321	0.670
10 hour Grid Centered	10 hour	13 hours	3.05E-03	0.017	0.067
10 hour Switchyard Centered	10 hour	13 hours	1.51E-03	0.016	0.113
10 hour Plant Centered	10 hour	13 hours	2.16E-04	0.012	0.107
10 hour Weather Related	10 hour	13 hours	1.88E-03	0.222	0.462

The results of this bin of the analysis yielded a core damage frequency (CDF) of 3.21E-5/year for this bin. When the base case risk (1.25E-5/year) was subtracted from the bin CDF value and applied to a 16 day time period, the core damage probability of 8.59E-7 results. This was annualized to obtain a bin CDF of 8.59E-7/year.

D. Risk Estimate for the 14-day period between June 16 and June 30, 2014:

During this exposure period, EDG No. 2 was assumed to have been capable of running for 4.6 hours. The LOOP frequencies were adjusted to reflect the situation that only LOOPs with durations greater than 4.5 hours would result in a risk increase attributable to the fan shaft failure.

The methodology was repeated from the previous bins. Time of t=0 needed to be reset to 4.5 hours following the LOOP event for the recovery factors for offsite power**.** Also, the same adjustments to account for the diminishment of decay heat were applied.

The results of this bin of the analysis yielded a CDF of 2.97E-5/year for this bin. When the base case risk (1.25E-5/year) was subtracted from the bin CDF value and applied to a 14 day time period, the core damage probability of 6.59E-7 results. This was annualized to obtain a bin CDF of 6.59E-7/year.

E. Combined Risk Estimate for Internal Events:

The following table presents the aggregate internal events result:

TIME PERIOD	DAYS OF EXPOSURE	DELTA CDF
July 28 - 29	1.8	1.52E-7
July 16 - 28	12	7.36E-7
June 30 - July 16	16	8.59E-7
June 16 - 30	14	6.59E-7
Total Internal Events Delta-CDF		**2.41E-6**

External Events Analysis:

The analyst utilized Oyster Creek's fire probabilistic risk assessment (PRA) to determine fire scenarios, which would become more risk significant without the availability of EDG NO. 2.

Fire in Switchyard. One fire area, Fire Area MT-FA-12, included the startup transformers. For postulated fires in this area, offsite power was assumed to be lost. The analyst substituted the initiating event value of such a fire from Oyster Creek's fire PRA (2.29E-3/year) and applied it to the internal events scenario for switchyard centered LOOPs. The analyst assumed that the fire removes offsite power. This was modeled by setting the startup transformers (described in the SPAR model as SB1 and SC1) to TRUE. The annualized CDF for this case of a switchyard centered LOOP was 8.59E-7. The conditional case sets the EDG No. 2 failing to run to TRUE. This results in a conditional CDF of 1.86E-5/year. Assuming the 44 day exposure period, the ΔCDF = 2.24E-6/year. The analyst noted this scenario was the dominant scenario.

Fire in Switchgear 1C. The analyst noted that one of the initiators for internal events which contributed significant risk to internal risk was a Loss of Switchgear 1C. This plant state would represent degradation of power to both redundant trains of power for the redundant trains of safety equipment. The analyst assumed a fire in Switchgear 1C would produce a similar scenario. An estimate was derived by applying the value for fire initiating event likelihood (of 6.19E-4/year) from the Oyster Creek Fire PRA. This value accounted for the fire ignition frequency, severity factor, and non-suppression factor, and was substituted for the Loss of 1C internal events initiating frequency. The analyst applied a 44 day exposure time to the results and obtained a change in CDF of 1.8E-7/year.

Fire in Switchgear 1A. Power to Switchgear 1C from offsite is fed by Switchgear 1A. Therefore, a loss of Switchgear 1A, would affect Switchgear 1C and have an impact on plant safety without EDG No. 2. The analyst performed a similar analysis as done with Switchgear 1C. The analyst applied a 44 day exposure time to the results and obtained a change in CDF of 2.7E-8/year.

Fire in 1A2. This fire scenario represented a fire in the control room cabinet which would give operators control of the equipment on Switchgears 1A and 1C. The analyst applied a 44 day exposure time to the results and obtained a change in CDF of 1.8E-7/year.

Many other fire scenarios were analyzed, but were determined to not be risk significant. The analyst combined the risk estimate of these fire scenarios to obtain a fire risk estimate of 2.64E-6/year.

Exelon shared their preliminary fire risk assessment of this condition with the analyst. Their result yielded an estimate of 5.5E-6 based on a 43 day exposure period. Of note, Exelon informed the analyst that their fire PRA was conservative and that the licensee removed some of the conservatisms from their model to obtain a more realistic risk estimate. Exelon had not shared this revised analysis with the analyst, but stated the value was above, but close to 1E-6/year based on a 43 day exposure period. The analyst considered this value to be comparable to the results obtained from the NRC analysis (2.66E-6/year based on a 44 day exposure period).

The analyst reviewed the risk due to EDG being unavailable during seismic events. The analyst used the seismic hazard vectors of Oyster Creek contained in Table 4A-1 of Volume 2 – External Events of the Risk Assessment of Operational Events Handbook. These vectors were applied to the switchyard insulators to verify any additional risk from a seismically induced LOOP. The analysis yielded an increase in risk of 2.1E-8, which the analyst considered negligible when compared to the internal events risk value.

The analyst reviewed Oyster Creek's Individual Plant Examination External Events (IPEEE) and did not consider flooding to be a significant risk contributor for this particular performance deficiency.

Based on the above, the analyst determined that only fire-related external events added significantly to the risk of the finding and it was estimated to be 2.64E-6/year.

Large Early Release Frequency (LERF)

The LERF assessment utilized NRC Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process." The failure of the fan shaft for EDG No. 2 was considered a Type A finding. The analyst screened out bins where EDG No. 2 was able to run for at least 12 hours, assuming that an early release was not possible with the diminishment of decay heat.

Appendix H, Table 5.2, "Phase 2 Assessment Factors – Type A Findings at Full Power," assumes 1.0 for high-pressure sequences with a dry drywell, and 0.6 for high-pressure sequences with a flooded drywell. The dry drywell value is bounding, but not necessarily conservative, in that liner melt-through is expected to occur shortly after vessel failure if the drywell is dry. The flooded drywell value is affected by the mode of reactor coolant system rupture, operator actions following the onset of core damage, and phenomenological issues related to direct containment heating and fuel-coolant interactions.

Exelon's preliminary analysis explicitly estimated LERF, and considers relevant high-pressure vessel breach phenomena (namely, fuel-coolant interaction, liner-melt-through, and direct containment heating). The multiplier for converting CDF to LERF according to the licensee was approximately 8E-2.

LERF FACTOR	ΔCDF	ΔLERF
Licensee PRA Factor (8E-2)	5.1E-6	4.1E-7
Appendix H, Flooded drywell (0.6)	5.1E-6	3.1E-6
Appendix H, Dry drywell (1.0)	5.1E-6	5.1E-6

The analyst assumed Exelon's value was a more representative estimation of LERF because the EDG would have run for at least 1.6 hours in the most conservative scenario, giving the operators time to commence plant depressurization. Recent evaluations (e.g., SOARCA Peach Bottom) have indicated that the likelihood of severe accident-induced main steam line creep rupture or a stuck-open relief valve prior to vessel breach is potentially higher than typically estimated in PRAs. This same case was made in a 2003 EPRI/NRC report titled "The Probability of High-Pressure Melt Ejection-Induced Direct Containment Heating Failure in Boiling Water Reactors with Mark I Design," These failure modes would lead to a more benign containment response at the time of vessel breach, in terms of direct containment heating and fuel-coolant interaction-induced containment failure.

Oyster Creek's Evaluation

Exelon performed their preliminary analysis using a 43-day exposure period. The analyst noted that Exelon employed the same "binning" methodology which the primary NRC analyst used, but instead the licensee used only one day of repair time.

Exelon used similar assumptions in their analysis derived from a report from their contracted party. It included 42 days of crack propagation and one day of repair to conclude that the exposure period was 43 days. (Inspectors' review of work documents determined that repair time was 1.75 days, hence the referral to 44 days in this document.) Exelon's result was 2.0E-6 when common cause was applied for EDG No. 1 for internal events only and 1.6E-6 when common cause was not applied. This was compared to 2.41E-6 for the NRC internal analysis. Without having Exelon's cutsets to review, the analyst could not perform a detailed cutset review and noted that the results did not differ significantly.

The analyst did note that Exelon's preliminary analysis also showed a LERF result with a value of 1.6E-7/year. The analyst concluded that this LERF value was accurate enough to demonstrate that LERF results would not drive a different conclusion than the CDF results.

Overall Risk Significance

The total change in core damage frequency for the period between June 16, 2014, and July 29, 2014 (44 days), was estimated as the sum of internal risk (2.41E-6) and external risk (2.64E-6) to obtain an aggregate risk of 5.1E-6/year.

Sensitivities

Use of a 211 day exposure period. The analyst considered use of a 211 day exposure period in the SPAR with common cause applied and crack development was considered. Internal events were estimated at 8.45E-6. Risk from external events (fire) was estimated at 1.26E-5/year. This yielded a combined change in CDF of 2.1E-5/year.

Use of a 100 day exposure period. The analyst considered use of a 100 day exposure period in the SPAR with common cause applied and failure to be only possible after crack initiation at 98 days prior to failure. This analysis was to estimate if crack growth had commenced earlier than the licensee postulated. Internal events were estimated at 4.61E-6. Risk from external events (fire) was estimated at 6.06E-6/year. This yielded a combined change in CDF of 1.1E-5/year. Of note, this result was near the White-Yellow threshold and demonstrates that including four additional “bins” of operational time would produce a Yellow risk result. This exposure period would be April 21 – July 29, 2014.

Common cause potential. The analyst performed a bounding internal events analysis using a 44 day exposure period with EDG No. 2 failed with the potential for common cause on EDG No. 1 (set EDG NO. 2 to TRUE in Systems Analysis Programs for Hands-On Evaluation (SAPHIRE)). This result did not credit any recovery of EDG No. 1 had it failed and assumed that EDG No. 2 was unavailable for any run time during the 44 day period. This analysis yielded a delta CDF of 4.0E-6/year for internal events only.

No common cause potential. The analyst performed an internal events analysis using a 44 day exposure period with EDG No. 2 failed without the potential for common cause on EDG No. 1 (set EDG No. 2 to 1.0 in SAPHIRE). This result did not credit any recovery of EDG No. 1 had it failed and assumed that EDG No. 2 was unavailable for any run time during the 44 day period. This analysis yielded a delta CDF of 3.1E-6/year for internal events only. This analysis was performed to judge the sensitivity to common cause.

Uncertainties

The bin between the June 30 and July 16 surveillance runs was examined for uncertainties because it was the most risk significant. The results of the analysis yielded a point estimate 3.37E-5. The median value was slightly lower at 2.70E-5 and the mean was higher at 6.64E-5. The confidence interval was 1.15E-5 – 7.14E-5. After sampling, the analyst considered these values to be representative of all bins which were analyzed. The analyst concluded that the uncertainty analysis gave confidence in the results of the point estimates of the 44 day and 211 day exposure periods.

ATTACHMENT 2: SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Exelon Personnel

G. Stathes, Site Vice-President
J. Dostal, Plant Manager
M. Ford, Director, Operations
D. Chernesky – Maintenance Director
G. Malone, Director, Engineering
C. Symonds, Director, Training
D. DiCello, Director, Work Management
M. McKenna, Manager, Regulatory Assurance
T. Farenga, Radiation Protection Manager
J. Renda, Manager, Environmental/Chemistry
T. Keenan, Manager, Site Security
H. Ray, Senior Manager, Design Engineering
E. Swain, Shift Operations Superintendent
T. Cappuccino, Regulatory Assurance Specialist
K. Paez, Regulatory Assurance Specialist

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened

05000219/2014005-02	AV	Inadequate Review of Change in Maintenance Process Results in Inoperable Emergency Diesel Generator (Section 4OA2.4)

Opened/Closed

05000219/2014005-01	NCV	Reactor Head Cooling Spray Piping Flange Misalignment (Section 1R08)
05000219/2014005-03	NCV	Plant Shutdown Procedure was Inadequate for Soft Shutdown (Section 4OA2.5)
05000219/2014005-04	NCV	Procedures Not Implemented During Plant Shutdown (Section 4OA2.5)

Closed

05000219/2013-005-01	LER	Reactor Protection System Actuation with Reactor in Hot Shutdown (Section 4OA3.2)
05000219/2014-003-00	LER	Technical Specification Prohibited Condition Caused by Emergency Diesel Generator Inoperable for Greater than Allowed Outage Time (Section 4OA3.3)

05000219/2014-004-00	LER	Local Leak Rate Test Results in Excess of Technical Specifications (Section 4OA3.4)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures
322, Service Water System, Revision 84
341, Emergency Diesel Generator Operation, Revision 108
ABN-31, High Winds, Revision 19
ABN-32, Abnormal Intake Level, Revision 24
OP-OC-108-109-1002, Cold Weather Freeze Inspection, Revision 4
WC-AA-107, Seasonal Readiness, Revision 14

Condition Reports (IRs)
2419178 2403104

Maintenance Orders/Work Orders
A2342119 A2347123 A2347412 A2347216

Miscellaneous
Oyster Creek Certification of 2014-2015 Winter Readiness, dated November 15, 2014

Section 1R04: Equipment Alignment

Procedures
308, Emergency Core Cooling System Operation, Revision 94
309.1, Turbine Building Closed Cooling Water System, Revision 57
310, Containment Spray System Operation, Revision 109
341, Emergency Diesel Generator Operation, Revision 108
ABN-32, Abnormal Intake Level, Revision 24
OP-AA-108-112, Plant Status and Configuration, Revision 8
OP-AA-108-117, Protected Equipment Program, Revision 4

Drawings
3E-862-21-1000, Emergency Diesel Generator Diesel Fuel Oil Storage & Transfer System, Revision 24
BR 2005 Sh. 2, Reactor & Turbine Building Service Water System, Revision 107
BR 2005 Sh. 4, Emergency Service Water System, Revision 86
BR 2006 Sh. 4, Turbine Building Closed Cooling Water System, Revision 65

Condition Reports (IRs)
2418411 2422230

Miscellaneous
Tagging Clearance # 14501238

Section 1R05: Fire Protection

Procedures
RB-FA-2, Reactor Building (Drywell and Torus), Revision 1
RB-FZ-1F4, Reactor Building (-19' Elevation) Northeast Corner Room, Revision 0
TB-FZ-11E, Condenser Bay Area (3'-6" Elevation), Revision 0

Section 1R06: Flood Protection Measures

Procedures
RAP-N1a, Fire Pump 1 Trouble, Revision 3
RAP-N2a, Fire Pump 2 Trouble, Revision 2
RAP-RB1C(1-7), 1-7 Sump Reactor Bldg Flr Drain Sump High Level, Revision 1

Condition Reports (IRs)
1692258 1698798

Maintenance Orders/Work Orders
R2143772 R2145964 R0802432 R2145964 R0803021

Miscellaneous
Component History Work Order Closure Remarks for Level Switch LS-572-4, dated November 24, 2014
Component History Work Order Closure Remarks for Valve V-24-35, dated November 26, 2014
Component History Work Order Closure Remarks for Valve V-24-38, dated November 26, 2014
Internal Flood Evaluation Summary and Notebook, Oyster Creek Nuclear Generating Station, dated April 17, 2008
OC-2010-S-0099, 50.59 Screening, RAP-N2a and RAP-N2b Procedure Changes, Revision 0
OP-OC-201-008-1018, Oyster Creek Generating Station Pre-Fire Plan, Control Room (OB-FZ-5), Revision 1
OP-OC-201-008-1019, Oyster Creek Generating Station Pre-Fire Plan, New Cable Spreading Room (OB-FZ-22A), Revision 1
Oyster Creek Nuclear Generating Station UFSAR, Section 9.3.3, Equipment and Floor Drainage Systems, Revision 16
Oyster Creek Nuclear Generating Station UFSAR, Table 9.3-4, Equipment and Floor Drainage System Components, Revision 16

Section 1R08: In-service Inspection

Procedures
2400-GMM-3900.52, Inspection and Torquing of Bolted Connections, Revision 7
CC-AA-407, Maintenance Specification: Evaluation and Repair of Piping and Equipment Flanges, Revision 2
ER-AA-330, Conduct of Inservice Inspection Activities, Revision 10
ER-AA-330-002, Inservice Inspection of Section XI Welds and Components, Revision 11
ER-AA-330-009, ASME Section XI Repair/Replacement-Program, Revision 8
ER-AA-335-002, Liquid Penetrant Examination, Revision 7
ER-AA-335-004, Ultrasonic Measurement of Material Thickness and Interfering Conditions, Revision 16
ER-AA-335-014, VT-1 Visual Examination, Revision 8
ER-AA-335-016, VT-3 Visual Examination of Component Supports, Attachments and Interiors of Reactor Vessels, Revision 9
ER-AA-335-018, Visual Examination of ASME IWE Class MC and Metallic Liners of IWL Class

CC Components, Revision 8
ER-OC-330-5001, ISI Program Plan, Fifth Ten-Year Inspection Interval, Revision 0
ER-OC-330-5002, ISI Classification Basis Document, Fifth Ten-Year Inspection Interval, Revision 0
GEH-PDI-UT-2, PDI Generic Procedure for the Ultrasonic Examination of Austenitic Pipes, Revision 6
GEH-UT-247, Procedure for Phased Array Ultrasonic Examination of Dissimilar Metal Welds, Revision 3
MA-OC-2015-001, Reactor Pressure Vessel Disassembly, Revision 11
MA-OC-205-004, Reactor Pressure Vessel Reassembly Preparation, Revision 4
PI-AA-120, Issue Identification and Screening Process, Revision 1
PI-AA-125, Corrective Action Program (CAP) Procedure, Revision 0

Condition Reports (IRs)

0836642	0842517	0845395	1135047	1430492	1435389
1437583	1441263	1441461	1441468	1444414	2363923
2386495	2381516	2385501	2386495	2392567	

Maintenance Orders/Work Orders
C2028889, ASME Section XI Repair/Replacement Plan N7B Flange Repair, dated November 27, 2012
C20300107, Replace Flange For NR02 Nozzle, dated September 30, 2014
C2032913, Replace Existing 2-inch V-31-5 Check Valve With New, dated September 23, 2014

NDE Inspection Reports & Data Sheets
Automated Encoded Phased Array UT Examination data of isolation condenser nozzle N5Asafe-end dissimilar metal weld NR02/1-566A, dated September 24, 2014
Automated Encoded Phased Array UT Examination data of isolation condenser nozzle N5B safe-end dissimilar metal weld NR02/1-566B, dated September 24, 2014
Automated Encoded Phased Array UT Examination data of reactor vessel reactor recirculation system outlet N1A safe-end-to-nozzle dissimilar metal weld NR02/4-565A, dated September 21, 2014
Automated Encoded Phased Array UT Examination data of reactor vessel reactor recirculation system outlet N1C safe-end-to-nozzle dissimilar metal weld NR02/4-565C, dated September 24, 2014
Automated Encoded Phased Array UT Examination data of reactor vessel reactor recirculation system outlet N1D safe-end-to-nozzle dissimilar metal weld NR02/4-565D, dated September 22, 2014
Liquid Penetrant Examination Data Sheet Report, 1R22-057, PT Head Cooling Spray Nozzle, dated October 31, 2008
Liquid Penetrant Examination Data Sheet Report, 1R22-061, PT Head Cooling Spray Nozzle, dated November 7, 2008
Liquid Penetrant Examination Reports No. BOP-PT-2014-013 and BOP-PT-2014-14, 9/25/14 UT Examination Report No. UT-14-052, dated September 25, 2014
Sand Bed Bay 1, Report 1R25-LRA-009, ASME IWE (CLASS MC) Containment and IWL (CLASS CC) Metallic Liners Visual Exam and NDE Report, dated September 21, 2014 and UT Thickness Measurement Report No. 1R25-LRA-010, dated September 21, 2014
Sand Bed Bay 11, Report 1R25-LRA-001, ASME IWE (CLASS MC) Containment and IWL (CLASS CC) Metallic Liners Visual Exam and NDE Report, dated September 19, 2014 and UT Thickness Measurement Report No. 1R25-LRA-002, dated September 19, 2014

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Sand Bed Bay 19, Report 1R25-LRA-011, ASME IWE (CLASS MC) Containment and IWL (CLASS CC) Metallic Liners Visual Exam and NDE Report, dated September 22, 2014 and UT Thickness Measurement Report No. 1R25-LRA-012, dated September 22, 2014
Sand Bed Bay 3, Report 1R25-LRA-003, ASME IWE (CLASS MC) Containment and IWL (CLASS CC) Metallic Liners Visual Exam and NDE Report, dated September 19, 2014 and UT Thickness Measurement Report No. 1R25-LRA-005, dated September 19, 2014
Sand Bed Bay 5, Report 1R25-LRA-004, ASME IWE (CLASS MC) Containment and IWL (CLASS CC) Metallic Liners Visual Exam and NDE Report, dated September 19, 2014 and UT Thickness Measurement Report No. 1R25-LRA-006, dated September 19, 2014
Sand Bed Bay 7, Report 1R25-LRA-007, ASME IWE (CLASS MC) Containment and IWL (CLASS CC) Metallic Liners Visual Exam and NDE Report, dated September 20, 2014 and UT Thickness Measurement Report No. 1R25-LRA-008, dated September 20, 2014
VT-1 Visual Examination NDE Report, 1R22-058, Spray Nozzle Penetration, dated November 5, 2008
VT-1 Visual Examination NDE Report, 1R22-062, Head Cooling Spray Nozzle, dated November 7, 2008
VT-2 Visual Examination NDE Sheet, Report No. R2143786, N7B flange, Post Repair Test during Plant Operational Pressure Test, dated December 4, 2012

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Engineering Evaluation for AR A2318125, Repair of N7B Flange, dated November 26, 2012
Structural Integrity Associates, Inc. CALCULATION PACKAGE, File No.: 0801436.301; Title: RPV Head Spray Line Cold-Spring Stress Evaluation, Revision 0 and Revision 1

Program Health Reports
Inservice Inspection (ISI) Program Health Reports 2nd, 3rd, 4th Quarter 2013
Inservice Inspection (ISI) Program Health Report 1st Quarter 2014

Section 1R11: Licensed Operator Requalification Program

Procedures
1001.22, Core Monitoring and Operation, Revision 51
201, Plant Startup, Revision 93
302.1, Control Rod Drive System, Revision 114
312.9, Primary Containment Control, Revision 58
315.1, Turbine Generator Startup, Revision 92
ABN-12, Turbine Generator Startup, Revision 92
OP-OC-101-111-1001, Strategies for Successful Transient Mitigation, Revision 8
OP-OC-101-111-1002, SOS Expectations, Revision 13
OP-OC-108-1001, Craft Capability, Revision 1
OP-OC-108-104-1001, Guidance for Limiting and Administrative Conditions for Operations, Revision 5
RAP, Generator Excitation Equipment Malfunction, Revision 4

Condition Reports (IRs)
02394977 02395136 02395202 02395293 02395452 02395730

Miscellaneous
OBE 14-6.1, Loss of B1 Bus/LBLOCA/Failure of No. 2 EDG, Revision 1
OCNGS EP 2014 Off Year Exercise, November 5, 2014

Section 1R12: Maintenance Effectiveness

Procedures
309.1, Turbine Building Closed Cooling Water System, Revision 57
ER-AA-310-1001, Maintenance Rule Scoping, Revision 4
ER-AA-310-1004, Maintenance Rule – Performance Monitoring, Revision 12
PI-AA-120, Issue Identification and Screening Process, Revision 1
PI-AA-125, Corrective Action Program (CAP) Procedure, Revision 0

Condition Reports (IRs)

1614197	1616472	1625920	1625923	1618476	2383814
2396328	2388149	2390832	1674492		

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
612.4.001, Standby Liquid Control Pump and Valve Operability and In-Service Test, Revision 49
WC-AA-101, On-Line Work Control Process, Revision 24

Condition Reports (IRs)
2425636

Miscellaneous
Oyster Creek Morning Report for November 14, 2014
Oyster Creek Morning Report for December 15, 2014
SC 14-19, 10 CFR Part 21 Communication: Failure of SBM Switch Q16SBMC3G31S1A2P1, dated December 11, 2014

Section 1R15: Operability Determinations and Functionality Assessments

Procedures
OP-AA-108-115, Operability Determinations, Revision 15
OP-AA-108-115-1002, Supplemental Consideration for On-Shift Immediate Operability Determinations, Revision 3

Condition Reports (IRs)

2417768	2418265	1694765

Miscellaneous
Oyster Creek Nuclear Generating Station Technical Specification 3.8, Isolation Condenser, Amendment 241
Oyster Creek Generating Station Standing Order, “Fire Water To Instrument Air Compressors,” dated November 28, 2014
Oyster Creek Generating Station Standing Order, “Fire Water To Isolation Condensers,” dated November 28, 2014

Section 1R18: Plant Modifications

Procedures
331, Office Building Heating, Ventilation and Air Conditioning System, Revision 69
2400-SMM-3219.02, Liquid Poison System Explosive Valve Maintenance, Revision 8
WC-AA-107, Seasonal Readiness, Revision 14

Condition Reports (IRs)

2429266	2419244	2415894	2415830	2415601	2415358
2414554	2414252	2414267	2414270	2414264	2414257
2414321					

Section 1R19: Post-Maintenance Testing

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624.4.001, Main Steam Valve Position Indication and IST Test, Revision 17
634.2.012, C1 Battery Charger Load Test, Revision 8
665.5.103, Main Steam Isolation Valve Leak Rate Test (South Header) (V-1-8/NS-03B & V-1-10/NS-04B), Revision 1
ER-OC-380, Oyster Creek Primary Containment Leakage Rate Testing Program, Revision 6
MA-AA-716-012, Post Maintenance Testing, Revision 19
OP-AA-108-106, Equipment Return to Service, Revision 4
OP-AA-108-115, Operability Determinations, Revision 15
WC-AA-101, On-Line Work Control Process, Revision 24

Condition Reports (IRs)

2383817	2383831	2383832	2383265	2392538	2405181
2428600					

Maintenance Orders/Work Orders

C2032911	R2215315	R2210392	R2161384	C2031083	A2366845
C2033274					

Miscellaneous
ECR 01-00628, 480V Circuit Breaker UV Device Replacement, dated March 18, 2003
NRC Inspection Manual Part 9900, Technical Guidance, dated April 16, 2008
Oyster Creek Nuclear Generating Station Technical Specification 4.5, Containment System, Amendment 262
Plant Process Computer Data for C Battery Voltage, dated October 22, 2014 through November 3, 2014
VM-OC-0526, Battery Charger C-1 & C-2 (Model 3S-130-500CD), Revision 7
VM-OC-0584, Agastat 7000 & 2400 Series Timing Relay Installation and Operation Manual, Revision 6
VM-OC-5016, GE Industrial Motors Including Custom 8000 Horizontal Motor (GEH-3160), Revision 7

Section 1R20: Refueling and Other Outage Activities

Procedures
201, Plant Startup, Revision 93
OP-AA-108-108, Unit Restart Review, Revision 15

Drawings
3E-153-02-009, General Arrangement, Reactor Building, Sections C-C, D-D & E-E, Revision 4

Condition Reports (IRs)

2395478	2395581	2390253	2390254	2394370	2394363
2394362	2394360	2394358	2394009	2393974	2393846
2393656	2394341	2394244	2394170	2391291	2390252
2390335	2391148	2391164	2387152	2390111	2390690
2390688	2390683	2390678	2390676	2390674	2390667
2390662	2391757	2391731	2391655	2391528	2391500
2391403	2387811	2391274	2391078	2390701	2390691
2390513	2392790	2392892	2392631	2392567	2392557
2392545	2392538	2392515	2392495	2392451	2392344
2392347	2392290	2392288	2392287	2392201	2391990
2391936	2391901	2391889	2391875	2391816	2391782
2388952	2388959	2383148	2381853	2183020	1691343
2381887	2383836	2385903	2345243	2382943	2386495

Maintenance Orders/Work Orders
R2212089 C2030852

Miscellaneous
ASME, Boiler and Pressure Vessel Code, Section XI: Inservice Inspection of Nuclear Power Plant Components, Section IWB-2420, Successive Inspections, 2007 Code with 2009 Addenda
OC1C25SU, Rod Control Sequence Review and Approval Sheet, dated October 1, 2014
Plant Oversight Review Committee Agenda Package, dated October 3, 2014
Plant Oversight Review Committee Agenda Package, dated October 7, 2014
Plant Oversight Review Committee Agenda Package, dated October 8, 2014
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Section 1R22: Surveillance Testing

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602.3.005, Automatic Depressurization System Actuation Circuit Test and Calibration, Revision 34
606.4.016, Containment Spray and Emergency Service Water System 1 Pump Operability and Quarterly Inservice Test. Revision 38
610.4.003, Core Spray Valve Operability and In-Service Test, Revision 44
636.4.002, Diesel Generator No. 2 Automatic Actuation Test, Revision 15
665.5.103, Main Steam Isolation Valve Leak Rate Test (South Header) (V-1-8/NS-03B & V-1-10/NS-04B), Revision 1
ER-OC-380, Oyster Creek Primary Containment Leakage Rate Testing Program, Revision 6
SP-1302-12-155, Oyster Creek Specification for Reactor Safety Valve Testing Nuclear Safety related ‘Q’, dated January 9, 2012

Condition Reports (IRs)

2383817	2383831	2383832	2383265	2391679	2391702
2400720	2391033	2391017	2391020	2391021	2391028
2391024	2391009	2390808	2391161	2391159	2391158
2391157	2391156				

Maintenance Orders/Work Orders
R2214615 R2247418 R2211655

Miscellaneous
ASME OM Code (2004 with 2006 Addenda) Mandatory Appendix I, Inservice Testing of Pressure Relief Devices in Light-Water Reactor Nuclear Power Plants
Oyster Creek Nuclear Generating Station Technical Specification 2.2, Safety Limit - Reactor Coolant System Pressure, Amendment 233
Oyster Creek Nuclear Generating Station Technical Specification 4.5, Containment System, Amendment 262
Oyster Creek Nuclear Generating Station Technical Specification 4.3, Reactor Coolant, Amendment 276
Oyster Creek Nuclear Generating Station Technical Specification 4.4.B, Automatic Depressurization, Amendment 276
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report Table 6.2-3, Containment Spray Pumps, Revision 14
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report Table 6.2-5, Containment Spray System Suction Valves, Revision 14
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report Table 6.2-6, Emergency Service Water Pumps, Revision 16
Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report Table 6.2-9, Containment Spray System Valves, Revision 14
Safety Valve Test Data for Valve BW05084, dated September 25, 2014
Safety Valve Test Data for Valve BY08715, dated September 25, 2014
United State Nuclear Regulatory Commission letter, "Oyster Creek Nuclear Generating Station – Relief From the Requirements of the ASME Code, Relief Request No. VR-01 for Fifth Inservice Testing Interval (TAC No. ME7617)," dated March 22, 2012

Section 1EP4: Emergency Action Level and Emergency Plan Changes

Procedures
EP-AA-114, Notifications, Revision 13

Section 1EP6: Drill Evaluation

Procedures
EP-AA-112-1 00-F-01, Shift Emergency Director Check List, Revision U
EP-AA-114-F-02, BWR Release in Progress Determination Guidance, Revision A
EP-AA-114-100-F-03, State/Local Notification Form, Revision H
EP-AA-122, Drills and Exercise Program, Revision 16

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621.3.001, ARM Radiation Monitoring Calibration and Test, Revision 38
621.3.005, High Radiation Monitor - RX. Bldg, Isolation - Calibration, Revision 54
621.3.019, Area Radiation Monitoring Trip Point Check and Power Supply Calibration, Revision 11
RP-AA-17 Radiological Instrumentation Program Description, Revision 0
RP-AA-700, Controls for Radiation Protection Instrumentation, Revision 3
RP-AA-700-1002, Determination of Correction Factors for Radiation Protection Neutron Meters, Revision 0
RP-AA-700-1100, Operation of the Eberline RO-2-2A-20, Bicron RSO 50E, Revision 0

RP-AA-700-1101, Calibration of the RO-2, RO-2A, RO-20 and RSO-50F Ion Chambers, Revision 1
RP-AA-700-1201, Operation of the MGP Instrument Telepole, Revision 1
RP-AA-700-1208, Operation of Shepherd Model 89 Calibrator, Revision 0
RP-AA-700-1214, Calibration of the PCM-1 Personnel Monitor, Revision 1
RP-AA-700-1215, Calibration of the Radeco Low-Vol Air Samplers, Revision 0
RP-AA-700-1224 Operation and Source Check Protean MPC-2000 Alpha Beta Counter, Revision 0
RP-AA-700-1235, Operation and Calibration of the PM-12 Contamination Portal Monitor, Revision 1
RP-AA-700-1239, Operation and Calibration of the Model SAM-12 Small Article Monitor, Revision 1
RP-AA-700-1240, Operation and Calibration of the Canberra ARGOS-5 Personnel Contamination Monitor, Revision 2
RP-AA-700-1249, Operation of the Ludlum Model 3, Revision 2
RP-AA-700-1250, Operation of Ludlum Model 3 w 43-92 Probe for Alpha Monitoring, Revision 0
RP-AA-700-1300, Calibration, Operation, and Source Check of the Eberline Beta Air Monitor, Model AMS-3, Revision 2
RP-AA-700-1301, Calibration, Source Check, Operation and Set-up of the Eberline Beta Air Monitor AMS-4, Revision 0
RP-AA-700-1302, Operation and Calibration of Portable Neutron Monitors, Revision I
RP-AA-700-1303, Bicron Micro-REM Survey Meter, Revision 0
RP-AA-700-1309, ASP-1 and AC-3 Alpha Survey Meters, Revision I
RP-AA-700-1310, Operation of the Thermo Electron FH 40 G-L and FH40 G-L FH-4, Revision 0
RP-AA-700-1311, Operation of ADM-300 Survey Meter, Revision 1
RP-AA-700-1401, Operation and Calibration of the Eberline Model PM-7 Personnel Contamination Monitor, Revision 1
RP-AA-700-1500, Operation and Source Check of the Ludlum 3030PAlpha-Beta Sample Counter, Revision 3
RP-AA-700-1501, Operation and Calibration of the Model SAM-9/11Small Article Monitor, Revision 1
RP-AA-700-230, Operation of the Canberra Fastscan Whole Body Counter, Revision 1
RP-OC-301-1002, Background, Efficiency, Operational Check Determination, and Performance of the Scaler Counting System, Revision 9
RP-OC-700-1100, Operation and Calibration of the CRONOS-11 Contamination Monitor, Revision 3
RP-OC-700-1500, Operation and Source Check of the Ludlum 3030PAlpha-Beta Sample Counter, Revision 0

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1528960	1580366	1580369	1554523	1589413	1618115
1623033	1545817	1686489	1545819		

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LS-AA-126-1005, Attachment 1 – Check-In Self-Assessment, AR 1611312, Nuclear Regulatory Commission Inspection IP 71124.05 Radiation Monitoring Instruments, July 29, 2014

LS-AA-126-1005, Attachment 1 – Check-In Self-Assessment, AR 1325216, Power Labs Vendor Audit, December 13, 2012
NOS-OYS-13-06, AR 1518342, Radiation Protection Program Audit Report, August 28, 2013

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Oyster Creek System Health Report, 661 – Radiation Monitoring System, Q1-2014
Oyster Creek System Health Report, 661 – Radiation Monitoring System, Q2-2014
Oyster Creek System Health Report, 661 – Radiation Monitoring System, Q3-2014
OC Daily Instrument Op-Check, dated October 15, 2014
OC Weekly Instrument Routine Air Sample Check List, dated October 20, 2014
PowerTraker Tool Available RP Active Instruments, dated October 24, 2014
OC List of Active RP and Chemistry Radiological Laboratory Instruments Used for Radioactive Analysis, dated October 20, 2014
OC Shared Inventory Summary with Number of Required Tools/Instruments, dated October 20, 2014
621.3.005, High Radiation Monitor – RX Bldg, Isolation – Calibration, dated March 14, 2014
621.3.005, High Radiation Monitor – RX Bldg, Isolation – Calibration, dated July 2, 2014
621.3.003, Main Steam Line Radiation Monitor Check Source Functional Test, dated October 25, 2013
Exelon PowerLabs Certificate of Calibration, Eberline ASP-1 , Serial No 339, dated October 7, 2014
Gamma Irradiation Services, Irradiation Inspection/Performance Calibration Test Report for EXELON Oyster Creek Nuclear Power Plant Sheppard and Air Irradiation Table, dated March 27, 2014
RP-AA-700 Attachment 1 Out of Tolerance Report Eberline RO2 Serial No. 332416, dated August 22, 2014
RP-AA-700 Attachment 1 Out of Tolerance Report Eberline RO2A Serial No. 076681, dated August 22, 2014
RP-AA-700 Attachment 1 Out of Tolerance Report ASP 2E w HP 270 Probe Serial No 079291
RP-AA-700 Attachment 1 Out of Tolerance Report Dosimeter AM-2 Serial No. 700073, dated June 4, 2014
RP-AA-700 Attachment 1 Out of Tolerance Report Eberline RO2A Serial No. 0013185, dated June 4, 2014
RP-OC-301-1002 Attachment 2, Count Room Instruments Operability Checks, dated October 23, 2014
RP-AA-700-1215, Attachment 7 Calibration Data Sheet: Eberline RAS-1 using Flow Calibrator, Serial No. 702454, dated October 23, 2014
RP-AA-700-1240, Attachment 1 Calibration Data Sheet: ARGOS-5, Serial No 1010-246, dated October 22, 2014
RP-AA-700-1401, Attachment 2, Calibration Data Sheet: PM-7 Portal Monitor, Serial No. 702449, dated October 22, 2014

Section 4OA1: Performance Indicator Verification

Procedures
EP-AA-125-1001, EP Performance Indicator Guidance, Revision 8
EP-AA-125-1002, ERO Performance – Performance Indicators Guidance, Revision 10
LS-AA-2001, Collecting and Reporting of NRC Performance Indicator Data, Revision 14
LS-AA-2110, Monthly Data Elements for NRC Emergency Response Organization (ERO) Drill Participation, Revision 6
LS-AA-2130, Monthly Data Elements for NRC Alert and Notification System (ANS) Reliability, Revision 5
LS-AA-2140, Monthly Data Elements for NRC Occupational Exposure Control Effectiveness, Revision 5
LS-AA-2150, Monthly Data Elements for RETS/ODCM Radiological Effluent Occurrences, Revision 5
LS-AA-2200, Mitigating System Performance Index Data Acquisition and Reporting, Revision 5

<u>Miscellaneous</u>
MSPI Margin Monthly Reports – 4Q2013 – 3Q2014
Nuclear Energy Institute Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7
Oyster Creek MSPI Basis Document
Oyster Creek Unit 1 – 4Q2013 – 3Q2014 MSPI Data, dated December 8, 2014

<u>Section 4OA2: Problem Identification and Resolution</u>

<u>Procedures</u>
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308, Emergency Core Cooling System Operation, Revision 94
341, Emergency Diesel Generator Operation, Revision 108
ABN-30, Control Room Evacuation, Revision 25
ABN-31, High Winds, Revision 19
ABN-60, Grid Emergency, Revision 15
AD-AA-101, Processing of Procedures and T&RMs, Revision 15
AD-AA-101-1000, Management Model Terminology and Direction, Revision 1
AD-AA-101-1002, Writer's Guide and Process Guide for Processing and T&RM, Revision 7
AD-AA-102, Station Qualified Review, Revision 5
CC-AA-102, Design Input and Configuration Change Impact Screening, Revision 6
CC-AA-103, Configuration Change Control, Revision 7
CC-AA-104, Document Change Request, Revision 14
CC-AA-11, Nonconforming Materials, Parts, or Components, Revision 5
CC-AA-309-101, Engineering Technical Evaluations, Revision 7 and 14
ER-AA-310-1004, Maintenance Rule – Performance Monitoring, Revision 11
LS-AA-104, Exelon 50.59 Review Process, Revision 4
LS-AA-104-1000, Exelon 50.59 Resource Manual, Revision 1
LS-AA-104-1001, 50.59 Review Coversheet, Revision 2
LS-AA-104-1002, 50.59 Applicability Review Form, Revision 2
LS-AA-106, Plant Operations Review Committee, Revision 1
LS-AA-120, Issue Identification and Screening Process, Revision 1
LS-AA-120, Issue Identification and Screening Process, Revision 4
LS-AA-125, Corrective Action Program, Revision 0
LS-OC-125, Corrective Action Program (CAP) Procedure, Revision 6
MA-OC-86103-100, Diesel Generator Fan Belt Replacement, Revision 0
MA-OC-861-101, Diesel Generator Inspection (24 Month) - Mechanical, Revision 17
OP-AA-101-111, Roles and Responsibilities of On-Shift Personnel, Rev 6
OP-AA-102-103, Operator Work-Around Program, Revision 4
OP-AA-102-103-1001, Operator Burden and Plant Significant Decisions Impact Assessment Program, Revision 6
OP-AA-106-101, Significant Event Reporting, Rev 16
OP-AA-108-105-1001, MCR and RWCR Equipment Deficiency Management and Performance Indicator Screening, Revision 5
OP-AA-115-101, Operator Aid Postings, Revision 2
OP-AA-3, Reactivity Management, Rev 1
OP-AA-300, Reactivity Management, Rev 6
OP-AA-300-1540, Reactivity Management Administration, Rev 10
OP-AB-300-1005, BWR Reactivity Management – Shutdown Activities, Rev 4
OP-OC-300-1001, Oyster Creek Reactivity SRO Guidelines, Rev 1
PI-AA-120, Issue Identification and Screening Process, Revision 1
PI-AA-125, Corrective Action Program (CAP) Procedure, Revision 0
Procedure 203, Plant Shutdown, Rev 75

Procedure 403.1, Operation of NI SRM Channel During and After Shutdown, Rev 11
WC-AA-106, Work Screening and Processing, Revision 15

Condition Reports (IRs)

2413117	1062005	1067996	1067996	1128036	1135900
1137564	1138066	1138066	1138066	1138809	1140050
1140312	1140821	1141413	1141981	1148348	1164020
1166208	1166848	1166848	1166848	1181950	1181958
1181999	1183062	1183064	1183066	1183067	1183069
1183070	1183075	1183080	1183081	1183084	1183086
1183087	1183088	1417235	1418769	1424714	1437014
1437317	1438253	1438256	1438256	1443312	1444861
1444862	1457722	1473767	1481670	1481670	1486185
1495758	1506509	1506509	1511787	1511787	1511787
1538843	1551624	1560524	1562515	1568796	1584827
1586565	1589077	1596563	1597136	1600245	1605092
1605095	1614019	1614019	1614019	1622182	1628481
1629184	1633161	1645010	1645010	1645010	1645572
1674814	1682905	1695263	1183076	1183078	2383948
2384908	2384931	2386534	2407283	2408095	2410105
2411800	1443312	1443313	2422565	2422586	2422705
2422885	2423821	1500241	1473767	1629184	1584827
1610014	1637438	2344845	2394011	2396328	2397633
2415358	2415697	2415894	2415898	2415936	2415939
2415947	2415998	2416045	2416791	2417635	2418002
2418011	2418265	2418411	2421785	2422319	2422497
1679865	1680667	1688410	1744563	2412093	2419138
1575377	1686101	1686767	1688727	1688756	1699147
2396154	2396163	2434265			

Maintenance Orders/Work Orders

C2032634	R2065452	R2151853	R2190622	R2202606	R2242349

Miscellaneous
OP-AA-102-103-1001 Attachment 1, Operator Burden/Degraded Equipment Aggregate Assessment, dated January 6, 2014, April 15, 2014 and July 18, 2014
Adverse Condition Monitoring Plan Log, dated December 10, 2014
Disabled Alarms Database, dated December 9, 2014
Control Room Narrative Log, dated December 5-12, 2014
Operational Decision Making Process Log, dated December 10, 2014
Operations Department Concerns List, dated December 9, 2014
Operator Challenge Database, dated December 9, 2014
Operator Work Arounds Database, dated December 9, 2014

Oyster Creek Forced Outage Scope, dated December 9, 2014
Oyster Creek Nuclear Generating Station Plan of the Day, dated December 9, 2014
Oyster Creek Online Priority Work List, dated December 9, 2014
Plant Air Leaks Database, dated December 9, 2014
Plant Oil Leaks Database, dated December 9, 2014
Plant Water Leaks Database, dated December 9, 2014
Temporary and Interim Procedure Changes Log, dated December 10, 2014
Apparent Cause Investigation Report, 1F34 Shutdown Reactivity Management Performance
Root Cause Investigation Report, Reactor Re-criticality During Soft Shutdown

ACIT 01686101-06, Technical Evaluation: Determine the Correct Installation Tension to be placed on the EDG-2 Cooling Fan Belt, dated September 9, 2014
ACIT 01686101-33, Technical Evaluation: Perform Owners Acceptance for Structural Integrity Report 1401386.401, dated January 6, 2015
Apparent Cause Evaluation (ACE) for AR 01686101, Emergency Diesel Generator Upper Fan Shaft Failure, dated September 28, 2014
Engineering Change Request (ECR) 13-00474, Fan Hitting Shroud, Revision 0
Exelon Position Paper to Address NRC Concerns Regarding Emergency Diesel Generator 2 Upper Fan Shaft Failure, dated November 21, 2014
Exelon Power Labs Project Number OYS-35189, Failure Analysis of Cooling Fan Shaft Section, dated August 13, 2014
Licensee Event Report (LER) 2004-001, #1 EDG Inoperable Caused by Cooling Fan Bearing Bolts Not Torqued Properly Following Preventative Maintenance Activities, Revision 00
LER 2014-003, Technical Specification Prohibited Condition Caused by Emergency Diesel Generator Inoperable for Greater than Allowed Outage Time, Revision 00
NRC Inspection Report Number 50-219/93-09, dated July 18, 1993
Operator Logs, Night Shift, dated July 28, 2014
Oyster Creek Generating Station Technical Specifications, Amendment 278
Oyster Creek Generating Station Updated Final Safety Analysis Report, Revision 18
Structural Integrity Associates Report Number 1400935.402.R0, Fracture Mechanics Evaluation of Failed Cooling Fan Shaft, dated August 8, 2014
Structural Integrity Associates Report Number 1401386.401.R0, Evaluation of Failed Cooling Fan Shaft, dated December 30, 2014
Technical Data Report 1120, Failure Analysis of a Fractured Emergency Diesel Shaft, dated September 13, 1993
VM-OC-0097, Maintenance Instruction M.I. 1200, MP45 Cooling Fan and Related Drive Train Assembly, Revision A

Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion

Procedures
315.1, Turbine Generator Startup, Revision 92
ABN-1, Reactor Scram, Revision 13

Condition Reports (IRs)
2394374 2394357

Maintenance Orders/Work Orders
R2211902 A0700966 R0800966

Miscellaneous
Event Notification 50476
Event Notification 50524
Human Performance Issue Verbal Report, dated October 14, 2014
Oyster Creek Nuclear Generating Station Operations Narrative Logs for October 12, 2014
Oyster Creek Nuclear Generating Station Outage Control Center Narrative Logs for September 18-19, 2014
Plant Process Computer data for October 12, 2014

LIST OF ACRONYMS

AC	Alternating Current
ADAMS	Agencywide Documents Access and Management System
ALARA	As-Low as Reasonably Achievable
ARM	Area Radiation Monitor
ASME	American Society of Mechanical Engineers
AV	Apparent Violation
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CPS	Counts per Second
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
Exelon	Exelon Nuclear
GPM	Gallons per Minute
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination External Events
IR	Issue Report
IRM	Intermediate Range Monitor
ISI	In-Service Inspection
KSI	Kips per Square Inch
LER	Licensee event report
LERF	Large Early Release Frequency
LOOP	Loss of Offsite Power
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NUREG	NRC technical report designation (Nuclear Regulatory Commission)
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
Oyster Creek	Oyster Creek Nuclear Generating Station
PI	Performance Indicator
PRA	Probabilistic Risk Analysis
PT	Dye Penetrant Test
RHC	Reactor Head Cooling
RHR	Residual Heat Removal
SAPHIRE	Systems Analysis Programs for Hands-On Evaluation
SCFH	Standard Cubic Feet per Hour
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SRM	Source Range Monitor
SSC	Structure, System, or Component
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Testing
VT	Visual Examination