APPENDIX F

UPDATED FINAL SAFETY ANALYSIS REPORT SUPPLEMENT
(LICENSE RENEWAL)

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TABLE OF CONTENTS

Note:
Section/Subsection identifiers begin with the letter "A" (instead of "F") to maintain consistency with the License Renewal Application and the NRC Safety Evaluation Report.

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

APPENDIX F
UPDATED FINAL SAFETY ANALYSIS REPORT SUPPLEMENT
(LICENSE RENEWAL)

LIST OF TABLES

APPENDIX F

UPDATED FINAL SAFETY ANALYSIS REPORT SUPPLEMENT (LICENSE RENEWAL)

A.1.0 Introduction

The application for a renewed operating license is required by 10 CFR 54.21(d) to include a FSAR Supplement. Note that the NRC imposed a requirement within the renewed operating licenses (i.e., license condition) requiring that changes to the UFSAR supplement (i.e., Appendix F) be evaluated in accordance with 10 CFR 50.59. This appendix, which includes the following sections, comprises the FSAR supplement:

- Section A.1.1 contains a listing of the aging management programs that correspond to NUREG-1801 Chapter XI programs, including the status of the programs at the time the License Renewal Application was submitted.
- Section A.1.2 contains a listing of the plant-specific aging management programs, including the status of the programs at the time the License Renewal Application was submitted.
- Section A.1.3 contains a listing of aging management programs that correspond to NUREG-1801 Chapter X programs associated with Time-Limited Aging Analyses, including the status of the programs at the time the License Renewal Application was submitted.
- Section A.1.4 contains a listing of the Time-Limited Aging Analyses summaries (TLAAs).
- Section A.1.5 contains a discussion of the Quality Assurance Program and Administrative Controls.
- Section A.1.6 contains a discussion of the Operating Experience program.
- Section A.2.0 contains a summarized description of the aging management programs.
- Section A.2.1 contains a summarized description of the NUREG-1801 Chapter XI programs for managing the effects of aging.
- Section A.2.2 contains a summarized description of the plant-specific programs for managing the effects of aging.

- Section A.3.0 contains a summarized description of the NUREG-1801 Chapter X programs that support the TLAAs.

- Section A.4.0 contains a summarized description of the TLAAs applicable to the period of extended operation.

- Section A.5.0 contains the License Renewal Commitment List.

The integrated plant assessment for license renewal identified new and existing aging management programs necessary to provide reasonable assurance that systems, structures, and components within the scope of license renewal will continue to perform their intended functions consistent with the Current Licensing Basis (CLB) for the period of extended operation. The period of extended operation (PEO) is defined as beginning at the unit's previous operating license expiration date and extending 20 years beyond that point.

A.1.0.1 Commitment Implementation Schedule Information

UFSAR Appendix F, Section A.5.0, License Renewal Commitment List contains the specific implementation schedule requirements for each commitment.

Consistent with the License Renewal Commitment list, when used throughout Appendix F the phrase "prior to the period of extended operation" means that:

- Implementation of new aging management programs and enhancements to existing aging management programs will be completed no later than six months prior to the respective period of extended operation (PEO) for each Byron and Braidwood unit; and

- Inspection or testing activities identified for completion prior to the PEO will be completed either:

  - No later than six months prior to the respective PEO for each Byron and Braidwood unit, or

  - Prior to the end of the last refueling outage before the PEO for each respective unit,

  whichever occurs later.

A.1.1 NUREG-1801 Chapter XI Aging Management Programs

The Byron and Braidwood NUREG-1801 Chapter XI Aging Management Programs (AMPs) are described in this section. The AMPs are either existing, existing with enhancements (enhanced) or new.

The following list reflects the status of these programs at the time of the License Renewal Application (LRA) submittal.

Commitments for program additions and enhancements are identified in the Appendix F, Section A.5.0, License Renewal Commitment List.

1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section A.2.1.1) [Existing - Requires Enhancement]

2. Water Chemistry (Section A.2.1.2) [Existing]

3. Reactor Head Closure Stud Bolting (Section A.2.1.3) [Existing - Requires Enhancement]

4. Boric Acid Corrosion (Section A.2.1.4) [Existing]

5. Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (Section A.2.1.5) [Existing]

6. Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (Section A.2.1.6) [New]

7. PWR Vessel Internals (Section A.2.1.7) [New]

8. Flow-Accelerated Corrosion (Section A.2.1.8) [Existing - Requires Enhancement]

9. Bolting Integrity (Section A.2.1.9) [Existing - Requires Enhancement]

10. Steam Generators (Section A.2.1.10) [Existing - Requires Enhancement]

11. Open-Cycle Cooling Water System (Section A.2.1.11) [Existing - Requires Enhancement]

12. Closed Treated Water Systems (Section A.2.1.12) [Existing - Requires Enhancement]

13. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section A.2.1.13) [Existing - Requires Enhancement]

14. Compressed Air Monitoring (Section A.2.1.14) [Existing - Requires Enhancement]

15. Fire Protection (Section A.2.1.15) [Existing - Requires Enhancement]

16. Fire Water System (Section A.2.1.16) [Existing - Requires Enhancement]

17. Aboveground Metallic Tanks (Section A.2.1.17) [New]

18. Fuel Oil Chemistry (Section A.2.1.18) [Existing - Requires Enhancement]

19. Reactor Vessel Surveillance (Section A.2.1.19) [Existing - Requires Enhancement]

20. One-Time Inspection (Section A.2.1.20) [New]

21. Selective Leaching (Section A.2.1.21) [New]

22. One-Time Inspection of ASME Code Class 1 Small-Bore Piping (Section A.2.1.22) [New]

23. External Surfaces Monitoring of Mechanical Components (Section A.2.1.23) [New]

24. Flux Thimble Tube Inspection (Section A.2.1.24) [Existing – Requires Enhancement]

25. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section A.2.1.25) [New]

26. Lubricating Oil Analysis (Section A.2.1.26) [Existing]

27. Monitoring of Neutron-Absorbing Materials Other than Boraflex (Section A.2.1.27) [Existing – Requires Enhancement]

28. Buried and Underground Piping (Section A.2.1.28) [Existing - Requires Enhancement]

29. ASME Section XI, Subsection IWE (Section A.2.1.29) [Existing - Requires Enhancement]

30. ASME Section XI, Subsection IWL (Section A.2.1.30) [Existing - Requires Enhancement]

31. ASME Section XI, Subsection IWF (Section A.2.1.31) [Existing - Requires Enhancement]

32. 10 CFR Part 50, Appendix J (Section A.2.1.32) [Existing]

33. Masonry Walls (Section A.2.1.33) [Existing - Requires Enhancement]

34. Structures Monitoring (Section A.2.1.34) [Existing - Requires Enhancement]

35. RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section A.2.1.35) [Existing - Requires Enhancement]

36. Protective Coating Monitoring and Maintenance Program (Section A.2.1.36) [Existing - Requires Enhancement]

37. Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.37) [New]

38. Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section A.2.1.38) [New]

39. Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.39) [New]

40. Metal-Enclosed Bus (Section A.2.1.40) [Existing - Requires Enhancement]

41. Fuse Holders (Byron Only) (Section A.2.1.41) [New]

42. Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.42) [New]

A.1.2 <u>Plant-Specific Aging Management Programs</u>

None. The Byron and Braidwood Stations, Units 1 and 2 License Renewal Application does not include plant-specific aging management programs.

A.1.3 <u>NUREG-1801 Chapter X Aging Management Programs</u>

The NUREG-1801 Chapter X Aging Management Programs (AMP) associated with Time-Limited Aging Analyses are described in the following sections. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-1801 Chapter X or require enhancements. The following list reflects the status of these programs at the time of the License Renewal Application (LRA) submittal. Commitments for program additions and enhancements are identified in Appendix F, Section A.5.0, License Renewal Commitment List.

1. Fatigue Monitoring (Section A.3.1.1) [Existing - Requires Enhancement]

2. Concrete Containment Tendon Prestress (Section A.3.1.2) [Existing - Requires Enhancement]

3. Environmental Qualification (EQ) of Electric Components (Section A.3.1.3) [Existing - Requires Enhancement]

A.1.4 <u>Time-Limited Aging Analyses</u>

Summaries of the Time-Limited Aging Analyses applicable to the period of extended operation are included in the following sections:

1. Reactor Vessel Neutron Embrittlement Analysis (Section A.4.2)

2. Metal Fatigue (Section A.4.3)

3. Environmental Qualification (EQ) of Electric Components (Section A.4.4)

4. Concrete Containment Tendon Prestress Analyses (Section A.4.5)

5. Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis (Section A.4.6)

6. Other Plant-Specific Time-Limited Aging Analyses (Section A.4.7)

A.1.5 Quality Assurance Program and Administrative Controls

The Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2, "Quality Assurance For Aging Management Programs (Branch Technical Position IQMB-1)" of NUREG-1800. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related systems, structures, and components (SSCs) that are subject to Aging Management Review (AMR).

A.1.6 Operating Experience

Operating experience from plant-specific and industry sources is captured and systematically reviewed on an ongoing basis in accordance with the Quality Assurance program, which meets the requirements of 10 CFR Appendix B, and the Operating Experience program, which meets the requirements of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff." The Operating Experience program interfaces with and relies on active participation in the Institute of Nuclear Power Operations' operating experience program, as endorsed by the NRC. The Operating Experience program will be enhanced to ensure, through the ongoing review of both internal and external operating experience, that the license renewal aging management programs are effective to manage the aging effects for which they are credited throughout the period of extended operation. The aging management programs are either enhanced or new programs developed when the review of operating experience indicates that the existing programs do not provide reasonable assurance that aging effects are being effectively managed.

Ongoing evaluation of operating experience related to aging management will begin no later than receipt of the renewed operating licenses, and will consider the following aspects, as appropriate:

- Systems, structures, or components that are similar or identical to those involved with the identified operating experience issue.

- Material of construction, operating environment, and aging effects associated with the identified aging issue so that lessons learned can be applied to susceptible SSCs within the scope of license renewal.

- Aging mechanisms associated with the operating experience to confirm that Byron and Braidwood Stations have appropriate AMPs in place to manage aging that could be caused by these mechanisms.

- AMPs associated with this operating experience so that if the AMPs have been demonstrated to be ineffective, similar AMPs in place at Byron and Braidwood Stations can be evaluated to determine if AMP changes are appropriate, or a new AMP is needed. Included in this review is consideration of activities, criteria, and evaluations integral to the elements of the plant AMPs.

The Operating Experience program has been enhanced to:

1. Require the review of internal and external operating experience for aging-related degradation or impacts to aging management activities, to determine if improvements to Byron and Braidwood Units 1 and 2 aging management activities are warranted. NRC and industry guidance documents and standards applicable to aging management are considered part of this information (e.g., License Renewal Interim Staff Guidance (LR-ISG) documents, NUREG-1801 (GALL) revisions, etc.) Ensure there are written expectations for identifying and processing these documents as operating experience.

2. Establish criteria to define aging-related degradation. In general, the criteria will be used to identify aging that is in excess of what would be expected, relative to design, previous inspection experience and the inspection intervals.

3. Establish identification coding within the corrective action program for use in identification, trending and communications of aging-related degradation. Provide a definition for the coding. This coding will assist plant personnel in ensuring that, in addition to addressing the specific issue, the adequacy of existing aging management programs is assessed. Station personnel are required to periodically assess the performance of the aging management programs, including insights obtained through operating

experience. Adverse trends are entered into the corrective action program for evaluation. This could lead to AMP revisions or the establishment of new AMPs, as appropriate.

4. Require communication of significant internal aging-related degradation, associated with SSCs in the scope of license renewal, to other Exelon plants and to the industry. Criteria will be established for determining when aging-related degradation is significant.

5. Provide training to those responsible for screening, evaluating and communicating operating experience items related to aging management and aging-related degradation. This training will be commensurate with their role in the process, will be provided periodically and include provisions to accommodate personnel turnover.

These enhancements were implemented prior to receipt of the renewed operating licenses, and will be conducted on an ongoing basis throughout the terms of the renewed licenses.

A.2.0 Aging Management Programs

A.2.1 NUREG-1801 Chapter XI Aging Management Programs

This section provides UFSAR summaries of the NUREG-1801 Chapter XI programs credited for managing the effects of aging.

A.2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is an existing condition-monitoring program that consists of periodic volumetric, surface, and/or visual examinations of ASME Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting for assessment, identification of signs of age-related degradation, and establishment of corrective actions. The program includes examinations and tests performed to identify and manage cracking, loss of fracture toughness, and loss of material in Class 1, 2, and 3 piping and components. This ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is implemented in accordance with 10 CFR 50.55a and ASME Code, Section XI, and is supplemented by EPRI Maintenance Reliability Programs MRP-146, "Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant Branch Lines" and MRP-192 (Braidwood only), "Assessment of RHR Mixing Tee Thermal Fatigue in PWR Plants." These activities include examinations, testing, detection, monitoring and trending, and evaluation of results to confirm that aging effects are managed during the period of extended operation.

The control rod drive mechanism (CRDM) thermal sleeves are examined under an augmented ISI inspection program. The scope of examination is to ultrasonically test (UT) the five (5) thermal sleeves with the worst wear on each unit. The plan for managing thermal sleeve wear is to obtain measured (UT) wear data points on each unit at the five (5) designated thermal sleeve reactor core locations during three (3) different outages. The frequency for inspection of the reactor vessel head thermal sleeve for loss of material due to wear will be re-evaluated after the accumulation of the three (3) data points on each of the five (5) designated thermal sleeves. The three (3) series of examinations will be performed prior to the period of extended operation. Subsequently, the required frequency for further inspections, if required, will be determined using the guidance provided in WCAP-16911-P, "Reactor Vessel Head Thermal Sleeve Wear Evaluation for Westinghouse Domestic Plants."

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program will be enhanced to:

1. Conduct a visual inspection of the accessible portions of the ASME Class 2 reactor vessel flange leakage monitoring tube every other refueling outage.

2. Perform non-destructive examination of the five (5) centermost CRDM housing penetrations to determine the thermal sleeve centering tab wear depth on the CRDM housing penetration inner diameter wall. On each unit, these CRDM housings will be examined at least once during the 10-year period prior to the period of extended operation, and on a 10-year frequency during the period of extended operation.

These enhancements will be implemented prior to the period of extended operation. The CRDM housing penetration examinations will be performed in accordance with the schedule described above.

A.2.1.2 Water Chemistry

The Water Chemistry aging management program is an existing mitigative program whose activities mitigate the loss of material due to corrosion, cracking due to stress corrosion cracking (SCC) and related mechanisms, and reduction of heat transfer due to fouling in components exposed to a reactor coolant, steam, treated borated water, and treated water environment. The program controls water chemistry for impurities (e.g., chloride, fluoride, and sulfate) that accelerate corrosion. Major component types include the reactor vessel, reactor internals, pressurizer vessel, steam generator internals, heat exchangers, tanks, piping, piping elements, and piping components. The primary system portion of this program consists of the reactor coolant system and related interfacing systems containing reactor coolant, treated borated water, and treated water. The secondary system portion of the program consists of the various secondary systems containing steam and treated water. The Byron and Braidwood Water Chemistry aging management program relies on monitoring and control of water chemistry to keep peak levels of various detrimental contaminants below system-specific limits, based on EPRI 3002000505, “PWR Primary Water Chemistry Guidelines,” Revision 7, and EPRI 3002010645, “Pressurized Water Reactor Secondary Water Chemistry Guidelines,” Revision 8.

A.2.1.3 Reactor Head Closure Stud Bolting

The Reactor Head Closure Stud Bolting aging management program is an existing preventive and condition monitoring program that provides for preventive and condition monitoring activities to manage reactor head closure studs and associated RPV head flange threads, nuts, and washers for cracking and loss of material.

The program is implemented through station procedures based on the examination and inspection requirements specified in ASME Code, Section XI, Table IWB-2500-1 and preventive measures to mitigate cracking. The program also relies on recommendations to address reactor head stud bolting aging-related degradation delineated in NUREG-1339 and NRC Regulatory Guide 1.65.

The Reactor Head Closure Stud Bolting aging management program will be enhanced to:

1. Revise the procurement requirements for reactor head closure stud material to assure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi.

This enhancement will be implemented prior to the period of extended operation.

A.2.1.4 Boric Acid Corrosion

The Boric Acid Corrosion aging management program is an existing condition monitoring program that manages the aging effects of mechanical, electrical, and structural components within the scope of license renewal that are susceptible to boric acid corrosion from systems that contain borated water. The Boric Acid Corrosion aging management program manages loss of material on piping, piping components, and piping elements, heat exchangers, ducting and components, containment liners, penetration bellows and sleeves, bolting, cabinets and enclosures, miscellaneous steel, and other structural components. The Boric Acid Corrosion aging management program manages increased resistance of connection/corrosion of connector contact surfaces on connector contacts for electrical connectors. The program consists of visual examinations of external surfaces that are potentially exposed to borated water leakage. The program includes walkdowns to allow timely discovery of leak paths and requires the removal of boric acid residues. The identification of the leakage source and the adjacent mechanical, electrical, and structural components in the leakage pathway area is performed to assess the damage.

Follow-up inspections are performed to ensure that the corrective actions were adequate and have addressed the identified age-related degradation. Additionally, the program includes examinations conducted during ISI pressure tests performed in accordance with the ASME Code, Section XI requirements. Walkdowns are performed prior to and after refueling outages as described in the response to NRC GL 88-05 dated May 31, 1988. This program is implemented in response to NRC GL 88-05 and operating experience.

A.2.1.5 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

The Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components aging management program is an existing condition monitoring program that manages primary water stress corrosion cracking (PWSCC) of nickel alloy-based components and associated welds, as well as loss of material due to boric acid induced corrosion in susceptible, safety-related components in the vicinity of nickel-alloy reactor coolant pressure boundary components. This condition monitoring program provides inspection requirements for the reactor pressure vessel components, steam generator primary components, pressurizer components, and reactor coolant system pressure boundary piping containing PWSCC susceptible materials designated alloys 600/82/182. The program also includes inspection requirements for reactor pressure vessel upper heads.

A.2.1.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program is a new condition monitoring program that provides assurance that reactor coolant pressure boundary CASS components (i.e., Class 1 piping and control rod assembly pressure boundary components) susceptible to thermal aging embrittlement meet their intended functions. The ASME Code Class 1 CASS components are maintained by inspecting and evaluating the extent of thermal aging embrittlement in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI. The Byron and Braidwood ASME Section XI Inservice Inspection program is augmented by the implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program which monitors the aging effect of loss of fracture toughness due to thermal aging embrittlement of ASME Code Class 1 CASS components with service conditions above 250 degrees Celsius (482 degrees Fahrenheit).

The Thermal Aging Embrittlement of CASS program will include a screening methodology to determine component susceptibility to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. For “potentially susceptible” components, thermal aging embrittlement management will be accomplished through either, qualified visual inspections, such as enhanced visual examination, qualified ultrasonic testing methodology, or component-specific flaw tolerance evaluation. Inspections or evaluations are not required for components that are determined not to be susceptible to thermal aging embrittlement. Screening for ASME Code Class 1 CASS components susceptible to thermal aging embrittlement is not required for pump casings and valve bodies. The existing ASME Section XI inspection requirements are adequate for managing the aging effects of Class 1 pump casings and valve bodies.

This new aging management program will be implemented prior to the period of extended operation.

A.2.1.7 PWR Vessel Internals

The PWR Vessel Internals aging management program is a new condition monitoring program that implements the guidance of EPRI 1022863 (MRP-227-A), "PWR Internals Inspection and Evaluation Guideline" and EPRI 1016609 (MRP-228), "Inspection Standard for PWR Internals" to manage the aging effects on reactor vessel internal (RVI) components.

The new program is used to manage the effects of age-related degradation that are applicable to the RVI components. These aging effects include: (a) various forms of cracking, including stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), irradiation assisted stress corrosion cracking (IASCC), or cracking due to fatigue/cyclical loading; (b) loss of material due to wear; (c) loss of fracture toughness due to neutron irradiation embrittlement; (d) changes in dimension due to void swelling and irradiation growth; and (e) loss of preload due to thermal and irradiation-enhanced stress relaxation or creep.

There are no RVI components that require additional aging management actions made of susceptible cast austenitic stainless steel, martensitic stainless steel, or precipitation-hardened stainless steel at the Byron and Braidwood Stations, therefore the aging effect of loss of fracture toughness due to thermal aging does not apply.

The PWR Vessel Internals aging management program is a new program and was implemented prior to receipt of the renewed operating licenses.

A.2.1.8 Flow-Accelerated Corrosion

The Flow-Accelerated Corrosion (FAC) aging management program is an existing condition monitoring program based on implementation of EPRI guidelines in NSAC-202L-R4, "Recommendations for an Effective Flow Accelerated Corrosion Program." Program activities include analyses to determine critical locations, baseline inspections to determine the extent of wall thinning at these critical locations, and follow-up inspections to confirm or quantify the predictions, and take long term corrective actions. Repairs and replacements are performed as necessary. Inspections are performed using ultrasonic, visual, or other approved testing techniques capable of detecting wall thinning. The program provides guidance for prediction, detection, and monitoring wall thinning in piping, piping components, and piping elements, and heat exchangers due to FAC.

The Flow-Accelerated Corrosion aging management program also manages wall thinning caused by mechanisms other than FAC, such as cavitation, flashing, droplet impingement, and solid particle impingement, in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanism(s).

The Flow-Accelerated Corrosion (FAC) aging management program will be enhanced to:

1. Revise program procedures to require the documentation of the validation and verification of updated vendor supplied FAC program software which calculates component wear, wear rates, remaining life, and next scheduled inspection. The validation and verification will verify that the updated software performs these calculations consistently with NSAC-202L-R4 guidelines.

This enhancement will be implemented prior to the period of extended operation.

A.2.1.9 Bolting Integrity

The Bolting Integrity aging management program is an existing condition monitoring program. The program provides for aging management for loss of preload, cracking, and loss of material due to corrosion of closure bolting on pressure retaining joints within the scope of license renewal. The Bolting Integrity program incorporates NRC and industry recommendations delineated in NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants,” EPRI NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” and EPRI TR-104213, “Bolted Joint Maintenance & Applications Guide.”

The program credits visual inspection of pressure retaining bolted joints in ASME Class 1, 2, and 3 systems for leakage and age-related degradation during system pressure tests performed in accordance with ASME Section XI, 2007 Edition through the 2008 Addenda at Byron and the 2013 Edition at Braidwood. In addition, the Bolting Integrity aging management program credits volumetric, surface, and visual inspections of ASME Class 1, 2, and 3 bolts, nuts, washers, and associated bolting components performed in accordance with ASME Section XI, Subsections IWB, IWC, and IWD. The integrity of non-ASME (nonsafety-related) pressure retaining bolted joints (in non-ASME Class 1, 2, 3 and MC systems) is monitored by detection of visible leakage, evidence of past leakage, or other age-related degradation during maintenance activities and walkdowns in plant areas that contain systems within scope of license renewal. Inspection activities of closure bolting on pressure retaining joints within the scope of license renewal in submerged environments will be performed in conjunction with associated component maintenance activities.

Additionally, non-pressure retaining bolting on the Byron and Braidwood integral reactor vessel head assembly and on the Braidwood 1A and 2A circulating water structure intake screens is managed by this program.

The Bolting Integrity aging management program is supplemented by ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program, as described in A.2.1.1, for inspection of safety-related closure bolting on pressure retaining joints. Inspection activities for closure bolting on pressure retaining joints in buried and underground environments are performed by the Buried and Underground Piping (A.2.1.28) program when closure bolting on pressure retaining joints are exposed by excavation.

The Primary Containment (MC) pressure bolting is managed as part of ASME Section XI, Subsection IWE (A.2.1.29) program. The ASME Section XI, Subsection IWF (A.2.1.31) program manages ASME Class 1, 2, 3 and MC piping and component supports bolting. Structural bolting, other than ASME Class 1, 2, 3, and MC piping and component supports is managed as part of the Structures Monitoring (A.2.1.34) program and R.G. 1.127, Inspection of Water Control Structures Associated With Nuclear Power Plants (A.2.1.35) program. Crane and hoist bolting is managed by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (A.2.1.13) program. The heating and ventilation system bolting is managed by the External Surfaces Monitoring of Mechanical Components (A.2.1.23) program. Reactor head closure bolting is managed by the Reactor Head Closure Stud Bolting (A.2.1.3) program. The above bolting is not included in the Bolting Integrity Program.

The Bolting Integrity aging management program will be enhanced to:

1. Prohibit the use of lubricants containing molybdenum disulfide on pressure retaining bolted joints.

2. Prohibit the use of high strength bolting (actual measured yield strength equal to or greater than 150 ksi) for pressure retaining bolted joints in portions of systems within the scope of the Bolting Integrity program.

3. Perform visual inspection of submerged bolting on fire protection system pumps (Byron only) and well water system deep well pumps (Byron only) when submerged portions of the pumps are overhauled or replaced during maintenance activities.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.10 Steam Generators

The Steam Generators aging management program is an existing preventive, mitigative, condition monitoring, and performance monitoring program. The program establishes the operation, maintenance, testing, inspection, and repair requirements for the steam generators to ensure that plant technical specification surveillance requirements, ASME Code requirements, the Maintenance Rule performance criteria are met, thereby adequately managing the aging effects of steam generator tubes, plugs, and secondary side internal components. The aging effects include cracking, loss of material, reduction of heat transfer, and wall thinning. The program identifies and maintains the steam generator design and licensing bases and implements NEI 97-06, "Steam Generator Program Guidelines." NEI 97-06 establishes a framework for prevention, inspection, evaluation, repair and leakage monitoring measures.

Tube sleeve repair is currently not allowed by plant technical specifications for Byron and Braidwood Stations, Unit 1 and Unit 2 nor are there any sleeves currently installed. If Byron and Braidwood Station (BBS) were to implement sleeving repair methods in the future, a Technical Specification change would be required and the sleeving would be incorporated into the Steam Generators aging management program.

The Steam Generators aging management program will be enhanced to:

1. Validate that primary water stress corrosion cracking of the divider plate welds to the primary head and tubesheet cladding is not occurring. BBS commits to perform one (1) of the following three (3) resolution options for Units 1 and 2:

   Option 1: Inspection

   Perform a one-time inspection, under the Steam Generators program, of each steam generator to assess the condition of the divider plate welds and the effectiveness of the Water Chemistry (A.2.1.2) program. For the Byron and Braidwood, Unit 1 steam generators which were replaced in 1998, the inspection will be performed between 2018 and the start of the period of extended operation to allow the steam generators to acquire at least twenty years of service. For the Byron and Braidwood, Unit 2 steam generators, which currently have at least twenty years of service, the inspection will be performed prior to entering the period of extended operation. The examination technique(s) will be capable of detecting primary water stress corrosion cracking (PWSCC) in the divider plate assemblies and associated welds.

or

Option 2: Analysis

Perform an analytical evaluation of the steam generator divider plate welds in order to establish a technical basis which concludes that the steam generator reactor coolant pressure boundary is adequately maintained with the presence of steam generator divider plate weld cracking. The analytical evaluation will be submitted to the NRC for review and approval two (2) years prior to entering the associated period of extended operation.

or

Option 3: Industry/NRC Studies

If results of industry and NRC studies and operating experience document that potential failure of the steam generator reactor coolant pressure boundary due to PWSCC of the steam generator divider plate welds is not a credible concern, this commitment will be revised to reflect that conclusion.

2. Validate that primary water stress corrosion cracking of the tube-to-tubesheet welds is not occurring on BBS Unit 1. BBS commit to perform one (1) of the following three (3) resolution options for Unit 1:

Option 1: Inspection

Perform a one-time inspection, under the Steam Generators program, of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. Since the Byron and Braidwood, Unit 1 steam generators were replaced in 1998, the inspection will be performed between 2018 and the start of the period of extended operation to allow the steam generators to acquire at least twenty years of service. The examination technique(s) will be capable of detecting primary water stress corrosion cracking (PWSCC) in the tube-to-tubesheet welds. If cracking is identified, the condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and a periodic monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.

or

Option 2: Analysis – Susceptibility

Perform an analytical evaluation of the steam generator tube-to-tubesheet welds to determine that the welds are not susceptible to primary water stress corrosion cracking. The evaluation for determining that the tube-to-tubesheet welds are not susceptible to primary water stress corrosion cracking will be submitted to the NRC for review and approval two (2) years prior to entering the associated period of extended operation.

or

Option 3: Analysis – Pressure Boundary

Perform an analytical evaluation of the steam generator tube-to-tubesheet welds redefining the reactor coolant pressure boundary of the tubes, where the steam generator tube-to-tubesheet welds are not required to perform a reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary will be submitted to the NRC for review and approval two (2) years prior to entering the associated period of extended operation.

These enhancements will be implemented prior to entering the period of extended operation.

A.2.1.11 Open-Cycle Cooling Water System

The Open-Cycle Cooling Water System (OCCWS) aging management program is an existing preventive, mitigative, condition monitoring, and performance monitoring program based on the implementation of NRC GL 89-13, which includes (a) surveillance and control of bio-fouling, (b) tests to verify heat transfer, (c) routine inspection and maintenance program, (d) system walkdown inspection, and (e) review of maintenance, operating, and training practices and procedures. The Open-Cycle Cooling Water System program applies to components constructed of various materials, including steel, stainless steel, gray cast iron, copper alloys, nickel alloys, titanium, and polymeric materials.

The OCCWS aging management program manages heat exchangers, piping, piping elements, and piping components in safety-related and nonsafety-related raw water systems that are exposed to a raw water environment for loss of material, loss of coating integrity, and reduction of heat transfer. The guidelines of NRC Generic Letter 89-13 are implemented through the site

GL 89-13 activities for heat exchangers and the Raw Water Corrosion program for piping segments. System and component testing, visual inspections, non-destructive examination (NDE) (i.e., ultrasonic testing and eddy current testing), and chemical injection are conducted to ensure that identified aging effects are managed such that system and component intended functions and integrity are maintained.

The OCCWS aging management program includes those systems that transfer heat from safety-related systems, structures, and components to the ultimate heat sink as defined in GL 89-13. Periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the sites' commitments to GL 89-13 to verify heat transfer capabilities. Additionally, safety-related piping segments are NDE tested periodically to ensure that there is no significant loss of material, which could cause a loss of intended function.

Safety-related and nonsafety-related piping inspections are performed using a 100% scan ultrasonic testing method, where possible, to ensure that localized corrosion indicative of microbiologically influenced corrosion (MIC) is detected. The inspections required by this program are performed at locations that are chosen to be leading indicators of the material condition of the internal surface of components within the scope of the program. The specific locations for inspections are chosen based on commitments made in the Byron and Braidwood responses to NRC GL 89-13, piping configuration, flow conditions (e.g., stagnant or low flow areas), and operating history (e.g., prior inspection results). The maximum interval for re-inspection is based on the calculated remaining life of the component. If required, piping replacement is performed prior to the development of through-wall leakage.

Periodic inspections of nonsafety-related heat exchangers, piping and piping components (including deep well pumps at Byron only) are being performed to manage aging effects. In scope, nonsafety-related heat exchangers do not have heat transfer intended functions, therefore, no heat transfer testing is performed. Nonsafety-related piping segments which have the potential for spatial interactions with safety-related equipment will be NDE tested periodically as delineated in Enhancement 1.

In addition, the internal coatings of components within the scope of this program are periodically visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. Inspections of internal coatings will be performed by qualified coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54. If peeling, blistering, or delamination is detected and the coating is not repaired, then physical testing will be conducted to ensure that the remaining coating is tightly bonded to the base metal and the as-left condition of the coating will be such that the potential for further degradation of the coating is minimized (i.e., any loose coating is removed, the edge of the remaining coating is feathered). The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07). Evidence of unacceptable coating degradation is entered into the corrective action program. The results of inspections of internal coatings are trended and used to adjust inspection frequencies as determined by the ASTM D7108 qualified Site Coating Coordinator.

The Open-Cycle Cooling Water System aging management program will be enhanced to:

1. Perform periodic volumetric inspections for loss of material in the non-essential service water system piping at a minimum of two (2) locations on each unit in both the auxiliary building and the turbine building for a total of four (4) periodic inspections per unit every refueling cycle.

2. Require inspections of internal coatings be performed by coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54.

3. Specify that signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the corrective action program.

4. Require physical testing of internal coatings, where physically possible, to ensure that remaining coating is tightly bonded to the base metal when peeling, blistering, or delamination is detected and the coating is not repaired or replaced. The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07).

5. Require that evaluations utilized to return a coated component exhibiting signs of peeling, blistering, or delamination to service without repairing or replacing the coating shall consider the potential impact on the intended function of the system. This evaluation shall include consideration of the potential for degraded performance of downstream components due to flow blockage and loss of material of the coated component.

6. Require the as-left condition of a coating that exhibited signs of peeling, blistering, or delamination and that is not repaired or replaced is such that the potential for further degradation of the coating is minimized.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.12 Closed Treated Water Systems

The Closed Treated Water Systems program is an existing mitigative and condition monitoring program that includes (a) nitrite-based and glycol-based water treatment, including pH control and the use of corrosion inhibitors, to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized; (b) chemical testing of the water to ensure that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of corrosion and/or cracking. The inspections include opportunistic inspections whenever the system boundary is opened as well as new periodic inspections described in Enhancement 1. The Closed Treated Water Systems program manages the loss of material, the reduction of heat transfer, and cracking in piping, piping components, piping elements, tanks, and heat exchangers.

The Closed Treated Water Systems aging management program will be enhanced to:

1. Perform condition monitoring, including periodic visual inspections and non-destructive examinations, to verify the effectiveness of water chemistry control at mitigating aging effects. A representative sample of piping and components will be selected based on likelihood of corrosion, fouling, or cracking and inspected at an interval not to exceed once in 10 years during the period of extended operation. The selection of components to be inspected will focus on locations which are most susceptible to age-related degradation, where practical.

2. Perform periodic sampling, analysis, and trending of water chemistry for the essential service water makeup pump engine glycol-based jacket water system to verify the effectiveness of water chemistry control at mitigating aging effects (Byron only).

These enhancements will be implemented prior to the period of extended operation.

A.2.1.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program is an existing condition monitoring program that evaluates the effectiveness of maintenance monitoring activities for cranes and hoists that are within the scope of license renewal. The existing activities consist of periodic visual inspections for loss of material on the structural components of the bridge, trolley, girders, bolting, and rails in the rail system. The program also manages loss of preload of associated bolted connections.

For those cranes or hoists with associated Time-Limited Aging Analyses, the effects of past and future usage, including the number and magnitude of lifts, are evaluated in Section 4.7.2 of the license renewal application.

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program will be enhanced to:

1. Consistently include inspections of structural components and bolting for loss of material due to corrosion, rails for loss of material due to wear and corrosion, and bolted connections for evidence of loss of preload.

2. Ensure periodic inspections are performed on all cranes, hoists, monorails, and rigging beams within the scope of license renewal, including those that are infrequently in use.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.14 Compressed Air Monitoring

The Compressed Air Monitoring aging management program is an existing condition and performance monitoring program that manages the loss of material on piping, piping elements, and piping components in the compressed air systems. The Compressed Air Monitoring aging management program includes monitoring of moisture content and contaminants such that specified limits are maintained and inspection of components for indications of loss of material.

The Compressed Air Monitoring aging management program is based on Byron and Braidwood Stations' response to NRC Generic Letter 88-14, "Instrument Air Supply Problems" and utilizes guidance and standards provided by ANSI/ISA-S7.3-1975, "Quality Standard for Instrument Air"; INPO SOER 88-01, "Instrument Air System Failures"; and ASME OM-S/G-1998, Part 17, "Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants."

The Compressed Air Monitoring aging management program activities implement the moisture content and contaminant criteria of ANSI/ISA-S7.3 (incorporated into ANSI/ISA-S7.0.01-1996). Program activities include air quality checks at various locations to ensure that dew point, particulates, and hydrocarbons are maintained within the specified limits and periodic inspections of select compressed air system component internal surfaces for signs of loss of material due to corrosion.

The Compressed Air Monitoring aging management program will be enhanced to:

1. Inspect critical component internal surfaces for signs of loss of material due to corrosion and document deficiencies in the corrective action program.

This enhancement will be implemented prior to the period of extended operation.

A.2.1.15 Fire Protection

The Fire Protection aging management program is an existing condition and performance monitoring program that includes various testing and inspections. This program requires the periodic visual inspection of fire barrier penetration seals; fire barrier walls, ceilings, and floors; fire resistant insulations and wraps; structural steel fireproofing; and combustible fluid retaining curbs and berms. These inspections will detect signs of age-related degradation; such as cracking, spalling, hardening, loss of bond, loss of form, loss of material, and loss of strength; prior to loss of intended function. The program also includes periodic visual inspections of fire doors and fire dampers, and periodic functional testing of fire doors to ensure that their operability is maintained. The Fire Protection aging management program also includes periodic inspection and testing of the halon and low-pressure carbon dioxide fire suppression systems to ensure age-related degradation is detected and corrected prior to loss of intended function. The periodic visual inspections and functional testing included in this aging management program ensure the fire protection barriers and system are maintained operational during the period of extended operation.

The Fire Protection aging management program will be enhanced to:

1. Include visual inspections of the earthen berm enclosing the outdoor fuel oil storage tanks for signs of age-related degradation such as loss of material and loss of form that could affect the intended function of the berm.

2. Provide additional inspection guidance to identify age-related degradation of fire barrier walls, ceilings, and floors or aging effects such as cracking, spalling, and loss of material.

3. Include visual inspection of halon and low-pressure carbon dioxide fire suppression system piping and component external surfaces for signs of corrosion or other age-related degradation.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.16 Fire Water System

The Fire Water System aging management program is an existing condition monitoring program that provides for system pressure monitoring, system header flushing, buried ring header flow testing, pump performance testing, hydrant full flow flushing and full flow verification, sprinkler and deluge system flushing and flow testing, hydrostatic testing, and inspection activities. Major component types managed by this program include sprinklers, fittings, valves, hydrants, hose stations, standpipes, tanks, pumps, and aboveground and buried piping and components. There are no underground (i.e., below grade but contained within a tunnel or vault) piping and components within the scope of the Fire Water System aging management program. This program manages aging effects of loss of material due to corrosion (including MIC), reduction in heat transfer due to fouling, and flow blockage due to fouling.

Opportunistic visual inspections, performed when the internal surface of the system is made accessible due to normal plant maintenance activities, and volumetric non-destructive examinations (i.e., guided wave, radiographic testing, and ultrasonic inspections) will be credited to ensure age related degradation is identified prior to loss of system intended function. Fire Protection System piping is risk ranked based on susceptibility to corrosion and consequences of leaks to determine locations for inspection. When volumetric examinations of Fire Protection System piping are performed and degradation is identified, additional inspections are performed in accordance with the following criteria:

- at least four (4) additional locations will be examined if wall loss is greater than 50 percent of nominal wall thickness,

- two (2) additional locations will be examined if wall loss is 30 percent to 50 percent of nominal wall thickness and the calculated remaining life is less than two (2) years,

- no additional examinations are required if wall loss is less than 30 percent of nominal wall thickness.

To ensure that sufficient volumetric examinations are performed such that age-related degradation is identified prior to loss of intended function, the Fire Water System program will be enhanced to require a minimum of 25 volumetric examinations, using radiographic testing or ultrasonic testing, every ten (10) years at both Byron and Braidwood independent of plant-specific operating experience. At Byron only, the program will be enhanced to require a minimum of 30 volumetric examinations, using radiographic testing or ultrasonic testing, during each three year interval to address recurring internal corrosion (RIC) due to MIC. If volumetric examinations over a 10-year interval do not identify three (3) or more areas exhibiting reduction in wall thickness greater than 50 percent, then RIC is no longer occurring and this minimum sample size is no longer required.

In addition, the program will be enhanced to perform additional inspections as described in the Enhancements below. Internal visual inspections or radiographic testing will be performed at the end of one (1) fire main and the end of one (1) branch line on half of the wet pipe sprinkler system every five (5) years. The wet pipe sprinkler systems that are not inspected during a five (5) year period will be inspected during the subsequent five (5) year period. Internal visual inspections are primarily relied upon for detection of flow blockage. Internal visual inspections are only capable of providing qualitative assessments of the internal condition of system piping with respect to loss of material. If unexpected levels of degradation are identified then the condition is entered into the corrective action program for evaluation. Unexpected levels of degradation include excessive accumulation of corrosion products and appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer.

At Braidwood only, periodic visual inspections of the traveling screens located upstream of the fire pumps are performed during diver inspections of 1A and 2A intake bays.

Buried ring header flow tests measure hydraulic resistance and compare results with previous testing as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of loss of material will be detected in a timely manner.

System functional tests, flow tests (including air flow tests), flushes, and inspections are performed in accordance with the applicable guidance from National Fire Protection Association (NFPA) codes and standards. The program will be enhanced to include annual main drain testing in accordance with NFPA 25, Section 13.2.5. These activities are performed periodically to ensure that the loss of material due to corrosion aging effect is managed such that the system and component intended functions are maintained.

In addition, the program will be enhanced to require portions of the water-based fire protection system that are: (a) normally dry but periodically subjected to flow and (b) cannot be drained or allow water to collect be subjected to augmented testing beyond that specified in NFPA 25. The augmented testing will include: (1) periodic full flow tests at the design pressure and flow rate or internal visual inspections and (2) volumetric wall-thickness examinations. Inspections and testing will commence five (5) years prior to the period of extended operation and will be conducted on a five (5) year frequency thereafter.

In addition, the internal coatings of components within the scope of this program are periodically visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. Inspections of internal coatings will be performed by qualified coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54. If peeling, blistering, or delamination is detected and the coating is not repaired, then physical testing will be conducted to ensure that the remaining coating is tightly bonded to the base metal and the as-left condition of the coating will be such that the potential for further degradation of the coating is minimized (i.e., any loose coating is removed, the edge of the remaining coating is feathered). The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07). Evidence of unacceptable coating degradation is entered into the corrective action program. The results of inspections of internal coatings are trended and used to adjust inspection frequencies as determined by the ASTM D7108 qualified Site Coating Coordinator.

The Fire Water System aging management program will be enhanced to:

1. Replace sprinkler heads or perform 50-year sprinkler head testing using the guidance of NFPA 25 "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2002 Edition), Section 5.3.1.1.1. This testing will be performed at the 50-year in-service date and every 10 years thereafter.

2. Provide for chemical addition, accompanied with system flushing to allow for adequate dispersal of the chemicals throughout the system, to prevent or minimize microbiologically induced corrosion (Byron only).

3. Perform main drain testing annually, in accordance with NFPA 25, “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems,” Section 13.2.5.

4. Perform air flow testing of deluge systems that are not subject to periodic full flow testing on a three (3) year frequency to verify that internal flow blockage is not occurring (Byron only).

5. Perform inspections of Fire Protection System strainers when the system is reset after automatic actuation for signs of internal flow blockage (e.g., buildup of corrosion particles) (Braidwood only).

6. Increase the frequency of visual inspections of the internal surface of the foam concentrate tanks to at least once every ten (10) years. At least one (1) inspection will be performed within the ten (10) year period prior to entry into the period of extended operation, with subsequent inspections performed every ten (10) years thereafter.

7. Perform radiographic testing or internal visual inspections every five (5) years at the end of one (1) fire main and the end of one (1) sprinkler system branch line in half of the wet pipe sprinkler system within the scope of license renewal. If internal flow blockage that could result in failure of the system to deliver the required flow is identified, then perform an obstruction investigation.

8. Perform augmented testing beyond that specified in NFPA 25 on those portions of the water-based fire protection system that are: (a) normally dry but periodically subjected to flow and (b) cannot be drained or allow water to collect. The augmented testing will include: (1) periodic full flow tests at the design pressure and flow rate or internal visual inspections and (2) volumetric wall-thickness examinations. Inspections and testing will commence five (5) years prior to the period of extended operation and will be conducted on a five (5) year frequency thereafter.

9. Perform a minimum of 30 volumetric examinations of Fire Protection System piping, using radiographic testing or ultrasonic testing, during each three year interval. If volumetric examinations over a 10-year interval do not identify three (3) or more areas exhibiting reduction in wall thickness greater than 50 percent, then this minimum sample size is no longer required. (Byron only)

10. Require inspections of internal coatings be performed by coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54.

11. Specify that signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the corrective action program.

12. Require physical testing of internal coatings, where physically possible, to ensure that remaining coating is tightly bonded to the base metal when peeling, blistering, or delamination is detected and the coating is not repaired or replaced. The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07).

13. Require that evaluations utilized to return a coated component exhibiting signs of peeling, blistering, or delamination to service without repairing or replacing the coating shall consider the potential impact on the intended function of the system. This evaluation shall include consideration of the potential for degraded performance of downstream components due to flow blockage and loss of material of the coated component.

14. Require the as-left condition of a coating that exhibited signs of peeling, blistering, or delamination and that is not repaired or replaced is such that the potential for further degradation of the coating is minimized.

15. Perform a minimum of 25 volumetric examinations of Fire Protection System piping using, radiographic testing or ultrasonic testing, during each 10-year interval.

These enhancements will be implemented prior to the period of extended operation, with the testing and inspections performed in accordance with the schedule described above.

A.2.1.17 Aboveground Metallic Tanks

The Aboveground Metallic Tanks program is a new condition monitoring program which manages loss of material and cracking on the external surfaces of aboveground metallic tanks within the scope of license renewal. The program applies only to aluminum condensate storage tanks which are supported on concrete and a four inch sand cushion above compacted backfill. There are no indoor tanks within the scope of this program. The condensate storage tanks are cathodically protected. The original plant design specifications do not require the aluminum condensate storage tanks to be coated or painted on the external surface as a preventive measure to mitigate corrosion. This is due to the corrosion resistance properties of aluminum. This program includes preventive measures to mitigate corrosion by protecting the external surfaces of metallic components, per standard industry practice, with sealant at the concrete-component interface.

The program requires periodic visual inspections once per eighteen (18) month operating cycle for degradation of the external surface of the insulation lagging, flashing, caulking, roof, and accessible sealant (sealant inspections are supplemented with physical manipulation). The program also requires periodic visual inspections and liquid penetrant examinations of the tank external surfaces at 25 locations for both tanks combined per site and includes, on a sampling basis, removal of selected tank lagging and insulation to permit inspections of the external tank surfaces and exposed sealants. The tank external surface inspections and examinations will be performed each 10-year period starting 10 years prior to the period of extended operation. The sample locations will include at least four locations below penetrations through the insulation and its jacketing (e.g. instrument nozzles, tank heaters, ladder). The remaining sample locations will be distributed such that inspections will occur on the tank dome, sides, and near the bottom.

One-time tank bottom ultrasonic inspections (one CST per station) will be performed within the 5-year period prior to the period of extended operation. The cathodic protection availability and effectiveness criteria in LR-ISG-2011-03 Table 4c, notes 3.ii and 3.iii, respectively, will be required to be met commencing 5 years prior to the PEO and during the PEO. The One-Time Inspection (B.2.1.20) aging management program supplements this program by providing for a one-time visual inspection of the internal surface of the CSTs to verify the effectiveness of the Water Chemistry (B.2.1.2) aging management program.

A.2.1.18 <u>Fuel Oil Chemistry</u>

The Fuel Oil Chemistry program is an existing mitigative and condition monitoring program that manages loss of material, loss of coating integrity, and reduction in heat transfer in piping, piping elements, piping components, tanks, and heat exchangers. The Fuel Oil Chemistry aging management program relies on a combination of surveillance procedures and maintenance activities being implemented to provide assurance that contaminants are monitored and controlled in fuel oil for systems and components within the scope of license renewal. The program requires fuel oil parameters to be maintained at acceptable levels in accordance with Technical Specifications, Technical Requirement Manual, and ASTM Standards (ASTM D 0975-98/-06b, D 2709-96e, D 4057-95, and D 5452-98). Fuel oil sampling and analysis is performed in accordance with approved procedures for new and stored fuel oil. Fuel oil tanks are periodically drained of accumulated water, cleaned, and internally inspected to minimize exposure to fuel oil contaminants. During these inspections, the internal coatings of the tanks are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. These activities effectively manage the effects of aging by maintaining contaminants at acceptably low concentrations.

Inspections of internal coatings will be performed by qualified coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54. If peeling, blistering, or delamination is detected and the coating is not repaired, then physical testing will be conducted to ensure that the remaining coating is tightly bonded to the base metal and the as-left condition of the coating will be such that the potential for further degradation of the coating is minimized (i.e., any loose coating is removed, the edge of the remaining coating is feathered). The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07). Evidence of unacceptable coating degradation is entered into the corrective action program. The results of inspections of internal coatings are trended and used to adjust inspection frequencies as determined by the ASTM D7108 qualified Site Coating Coordinator. In addition, the instrumentation and alarms related to emergency diesel generator fuel oil storage tank level and fuel oil transfer pump suction strainer differential pressure are monitored. Monitoring of instrumentation related to the coated emergency diesel generator fuel oil storage tank ensures that an adequate fuel oil supply is available such that the intended functions of the emergency diesel generators are maintained. High differential pressure across the fuel oil transfer pump suction strainer would provide indication if any significant degradation of the coating were to occur and cause coating debris to enter the fuel oil transfer system.

The Fuel Oil Chemistry aging management program will be enhanced to:

1. Provide for the periodic cleaning of the Fire Protection Fuel Oil Storage Tank (Byron only).

2. Provide for periodic draining of water from the Auxiliary Feedwater Day Tanks, Diesel Generator Day Tanks, Essential Service Water Make/Up Pump Fuel Oil Storage Tanks (Byron only), and Fire Protection Fuel Oil Storage Tanks.

3. Include analysis for the levels of microbiological organisms in the Auxiliary Feedwater Day Tanks and Essential Service Water Make-up Pumps Diesel Oil Storage Tanks (Byron only).

4. Include analysis for water and sediment content, particulate concentration, and the levels of microbiological organisms for the Diesel Generator Day Tanks.

5. Include analysis for water and sediment content and the levels of microbiological organisms for the Diesel Generator Fuel Oil Storage Tanks.

6. Include analysis for particulate concentration and the levels of microbiological organisms for the Fire Protection Fuel Oil Storage Tanks.

7. Include internal inspections of the Fire Protection Fuel Oil Storage Tanks at least once during the 10 year period prior to the period of extended operation, and at least once every 10 years during the period of extended operation. Each diesel fuel tank will be drained and cleaned, the internal surfaces visually inspected (if physically possible), and, if evidence of degradation is observed during inspections, or if visual inspection is not possible, these diesel fuel tanks will be volumetrically inspected.

8. Include monitoring and trending for the levels of microbiological organisms for the Auxiliary Feedwater Day Tanks and Essential Service Water Make-up Pumps Diesel Oil Storage Tanks (Byron only).

9. Include monitoring and trending for water and sediment content, particulate concentration, and the levels of microbiological organisms for the Diesel Generator Day Tanks.

10. Include monitoring and trending for water and sediment content and the levels of microbiological organisms for the Diesel Generator Fuel Oil Storage Tanks.

11. Include monitoring and trending for total particulate concentration and the levels of microbiological organisms for the Fire Protection Fuel Oil Storage Tanks.

12. Require inspections of internal coatings be performed by coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54.

13. Specify that signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the corrective action program.

14. Require physical testing of internal coatings, where physically possible, to ensure that remaining coating is tightly bonded to the base metal when peeling, blistering, or delamination is detected and the coating is not repaired or replaced. The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07).

15. Require that evaluations utilized to return a coated component exhibiting signs of peeling, blistering, or delamination to service without repairing or replacing the coating shall consider the potential impact on the intended function of the system. This evaluation shall include consideration of the potential for degraded performance of downstream components due to flow blockage and loss of material of the coated component.

16. Require the as-left condition of a coating that exhibited signs of peeling, blistering, or delamination and that is not repaired or replaced is such that the potential for further degradation of the coating is minimized.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.19 Reactor Vessel Surveillance

The Reactor Vessel Surveillance aging management program is an existing condition monitoring program that extends the scope of 10 CFR Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements." The program provides sufficient material and dosimetry data to monitor loss of fracture toughness due to neutron irradiation embrittlement until the end of the period of extended operation, and determine the need for operating restrictions on the irradiation temperature (i.e., cold leg operating temperature), neutron spectrum, and neutron fluence. There were six (6) specimen capsules installed in each BBS reactor pressure vessel (RPV) prior to plant start-up. The capsules contain representative RPV material specimens, neutron dosimeters, and thermal monitors (eutectic alloy). All six (6) specimen capsules have been withdrawn from each of the BBS RPVs. Three (3) specimen capsules from each RPV were tested and the remaining three (3) untested specimen capsules from each RPV are currently stored in the spent fuel pool. Of the three (3) untested specimen capsules from each RPV at least one (1) untested specimen capsule has been irradiated in excess of the projected peak neutron fluence of the associated RPV at the end of the period of extended operation. Capsules that have been withdrawn will be tested as necessary to fulfill the surveillance capsule recommendations contained in ASTM 185-82 as required by 10 CFR Part 50, Appendix H. Operating restrictions will be established to ensure that the plant is operated under the conditions to which the surveillance capsules were exposed. All capsules tested for the period of extended operation will meet the test procedures and reporting requirements of ASTM E 185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels" to the extent practicable for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the NRC prior to implementation. Untested capsules placed in storage must be maintained for possible future insertion.

The program also monitors plant operating conditions to ensure appropriate steps are taken if reactor vessel exposure conditions are altered, such as the review and updating of 60-year fluence projections to support upper shelf energy calculations and pressure-temperature limit curves. The program also includes condition monitoring by removal and analysis of ex-core neutron dosimetry sensor sets to validate neutron exposure projection calculations through the period of extended operation in accordance with Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." These measures are effective in monitoring the extent of neutron irradiation embrittlement to prevent significant degradation of the reactor pressure vessel during the period of extended operation.

The Reactor Vessel Surveillance aging management program will be enhanced to:

1. Establish operating restrictions to ensure that the plant is operated under the conditions to which the surveillance capsules were exposed. The operating restrictions are as follows:

   Byron Station, Unit 1:

   - Cold leg operating temperature limitation: 525 degrees Fahrenheit (minimum) to 590 degrees Fahrenheit (maximum)

   - RPV beltline material fluence: 3.21E+19 n/cm2 (E >1.0 MeV) (maximum)

   Byron Station, Unit 2; Braidwood Station Unit 1:

   - Cold leg operating temperature limitation: 525 degrees Fahrenheit (minimum) to 590 degrees Fahrenheit (maximum)

   - RPV beltline material fluence: 3.19E+19 n/cm2 (E >1.0 MeV) (maximum)

Braidwood Station, Unit 2:

- Cold leg operating temperature limitation: 525 degrees Fahrenheit (minimum) to 590 degrees Fahrenheit (maximum)

- RPV beltline material fluence: 3.16E+19 n/cm2 (E >1.0 MeV) (maximum)

If the reactor pressure vessel exposure conditions (neutron fluence, neutron spectrum) or irradiation temperature (cold leg inlet temperature) are altered, then the basis for the projection to the end of the period of extended operation needs to be reviewed and, if deemed appropriate, updates are made to the Reactor Vessel Surveillance program. Any changes to the Reactor Vessel Surveillance program must be submitted for NRC review and approval in accordance with 10 CFR Part 50, Appendix H.

2. One (1) specimen capsule per reactor vessel, as designated below, irradiated to a neutron fluence of one (1) to two (2) times the projected peak neutron fluence at the end of the period of extended operation will be withdrawn from the spent fuel pool, tested, and the summary technical report submitted to the NRC within one (1) year of receipt of the renewed license. Alternatively, if a request for extension of the testing schedule is submitted in accordance with 10 CFR Part 50, Appendix H and granted by the Director, Office of Nuclear Reactor Regulation, specimen testing will be performed in accordance with that approved extension.

Reactor Vessel (Station, Unit)	Capsule ID	Capsule Fluence (n/cm^2)(E>1.0 MeV)
Byron, Unit 1	Y	3.97E+19
Byron, Unit 2	Y	4.19E+19
Braidwood, Unit 1	V	3.71E+19
Braidwood, Unit 2	V	3.73E+19

These enhancements will be implemented prior to the period of extended operation, with the testing of the reactor vessel specimen capsules performed in accordance with the schedule described above.

A.2.1.20 <u>One-Time Inspection</u>

The One-Time Inspection aging management program is a new condition monitoring program that will be used to verify the system-wide effectiveness of the Water Chemistry (A.2.1.2) program, Fuel Oil Chemistry (A.2.1.18) program, and Lubricating

Oil Analysis (A.2.1.26) program which are designed to prevent or minimize age-related degradation so that there will not be a loss of intended function during the period of extended operation. The program manages loss of material, cracking, and reduction of heat transfer in piping, piping components, piping elements, tanks, pump casings, heat exchangers, and other components within the scope of license renewal. The program identifies inspections focused on locations that are isolated from the flow stream, that are stagnant, or that have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. A representative sample size of 20 percent of the population (up to a maximum of 25 component inspections) will be established for each of the sample groups and will focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions. The program verifies either no unacceptable age-related degradation is occurring or triggers additional actions that will assure the intended function of affected components will be maintained during the period of extended operation.

The One-Time Inspection aging management program will also be utilized, in specific cases where existing data is insufficient:

a) to validate that a particular aging effect is not occurring, or

b) to verify that the aging effect is occurring slowly enough to not affect a components intended function during the period of extended operation.

In these cases, the components will not require additional aging management.

The One-Time Inspection aging management program will include inspections of insulated and uninsulated stainless steel or aluminum alloy piping and components located outdoors to verify that stress corrosion cracking is not occurring or is occurring slowly enough to not affect a components intended function during the period of extended operation.

The elements of the program include (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and plant-specific and industry operating experience, (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could adversely impact an intended function before the end of the period of extended operation.

This program is not used for systems or components with known age-related degradation or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years. Periodic inspections will be used in these cases.

The One-Time Inspection program will be implemented prior to the period of extended operation. The one-time inspections will be performed within the 10 year period prior to the period of extended operation.

A.2.1.21 Selective Leaching

The Selective Leaching aging management program is a new condition monitoring program that includes one-time inspections to demonstrate the absence of selective leaching of a representative sample of susceptible components within the scope of license renewal. Components include piping and fittings, valve bodies, pump casings, heat exchanger components, and structural members. The materials of construction for these components are gray cast iron and copper alloy with greater than 15 percent zinc. There are no aluminum bronze in-scope components with greater than eight (8) percent aluminum. A sample size of 20 percent of susceptible components will be subject to a one-time inspection with a maximum of 25 inspections for each of the susceptible material and environment combination groups.

These one-time inspections for loss of material due to selective leaching will include visual examinations, supplemented by hardness tests or other mechanical examination techniques such as destructive testing, scraping, or chipping of selected components that are susceptible to selective leaching. These inspections are to determine whether loss of material due to selective leaching is occurring and whether the process will affect the ability of the components to perform their intended function during the period of extended operation. The material degradation evaluation may require confirmation of selective leaching through a metallurgical evaluation. If loss of material due to selective leaching is identified, further evaluation of the extent of selective leaching will be performed under the corrective action program, which may include an expansion of the inspection sample size and locations.

The Selective Leaching aging management program will be implemented prior to the period of extended operation. One-time inspections will be performed within the five (5) year period prior to entering the period of extended operation.

A.2.1.22 One-Time Inspection of ASME Code Class 1 Small-Bore Piping

The One-Time Inspection of ASME Code Class 1 Small-Bore Piping aging management program is a new condition monitoring program that will manage the aging effect of cracking in ASME Code Class 1 small-bore piping that is less than nominal pipe size of four (4) inches (NPS 4), and greater than or equal to one (1) inch (NPS 1). The program, which includes pipes, fittings, branch fittings, branch connections, and all associated full penetration (butt) and partial penetration (socket) welds, will augment ASME Code, Section XI requirements. The program includes measures to verify that degradation is not occurring or aging is insignificant, thereby, either confirming that there is no need to manage aging-related degradation or validating the effectiveness of any existing program for the period of extended operation.

The program implements one-time inspection of a sample of piping full penetration (butt) and partial penetration (socket) welds that are susceptible to cracking using volumetric examinations. The inspection sample size will include 10% of the socket weld population up to a maximum of 25 socket welds for each Byron and Braidwood unit and 10% of the butt weld population up to a maximum of 25 butt welds for each Byron and Braidwood unit. The socket weld sample population for Byron Unit 1 will include the socket weld on the “D” safety injection system cold leg injection line that was replaced in 1998. Inspection of socket welds will be performed by volumetric examination techniques demonstrated to be capable of detecting cracking. If such volumetric techniques are not available by the time of the inspections, the examination method will be by destructive testing. If destructive testing is performed, each socket weld test will be credited as equivalent to two volumetrically examined welds. Inspections required by the program will augment ASME Code, Section XI requirements, as applicable.

Cracking of ASME Code Class 1 small-bore piping due to intergranular stress corrosion or fatigue due to cyclical loading has not been experienced at Byron and Braidwood Stations. Therefore, this one-time inspection program is applicable and adequate to manage this aging effect for the period of extended operation. A plant specific periodic inspection program will be implemented if evidence of cracking caused by intergranular stress corrosion or fatigue due to cyclical loading is revealed in ASME Code Class 1 small-bore piping, and design changes have not been implemented to correct the cause.

The new One-Time Inspection of ASME Code Class 1 Small-Bore Piping aging management program will be implemented prior to the period of extended operation. One-time inspections will be performed and evaluated within the six (6) year period prior to the period of extended operation.

A.2.1.23 External Surfaces Monitoring of Mechanical Components

The External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that directs visual inspections of external surfaces of components be performed during system inspections and walkdowns. The program consists of periodic visual inspections of metallic and elastomeric components such as piping, piping components, ducting, elastomeric components, and other components within the scope of license renewal. The program manages aging effects of metallic and elastomeric components through visual inspection of external surfaces for evidence of loss of material and cracking. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers. The periodic system walkdowns include visual inspection of insulation jacketing to ensure the integrity of the jacketing is maintained. External visual inspections of the jacketing ensure that there is no damage to the jacketing that would permit in-leakage of moisture. The procedures for planning insulation repairs will be revised to document that insulation repairs are performed in accordance with specification requirements (e.g., seams on the bottom, overlapping seams) so as to prevent water intrusion into the insulation.

Periodic representative inspections to detect corrosion (i.e. loss of material) under insulation will be conducted on in-scope indoor insulated components, where the process fluid temperature is below the dew point for a period of time sufficient to accumulate condensation, and in-scope outdoor insulated components (with the exception of the condensate storage tanks). These periodic inspections will be conducted during each 10-year period of the period of extended operation. Inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), then periodic visual inspections under insulation to detect corrosion and cracking under insulation will continue.

The external surfaces of components that are buried are inspected via the Buried and Underground Piping (A.2.1.28) program. The external surfaces of above ground tanks are inspected via the Aboveground Metallic Tanks (A.2.1.17) program. Internal surfaces are inspected via the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (A.2.1.25) program.

This new aging management program will be implemented prior to the period of extended operation.

A.2.1.24 Flux Thimble Tube Inspection

The Flux Thimble Tube Inspection aging management program is an existing condition monitoring program that manages the loss of material in flux thimble tubes due to wear (i.e., wall thinning). Flux thimble tubes, which provide a path for the in-core neutron flux monitoring system detectors, establish part of the reactor coolant pressure boundary and are subject to flow-induced fretting which causes wear. The program uses the non-destructive examination methodology of eddy current testing to periodically inspect the full length of all flux thimble tubes, which encompasses the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide. The results of the periodic eddy current testing are evaluated and trended to determine if corrective actions are required or if the inspection frequency needs to be changed to ensure reactor coolant pressure boundary integrity is maintained. Corrective actions include flux thimble tube limited repositioning (one-time), replacement, or isolation (removal from service).

The Flux Thimble Tube Inspection program implements the recommendations of NRC IE Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors." This existing aging management program will continue to be implemented during the period of extended operation.

The Flux Thimble Tube Inspection aging management program will be enhanced as follows:

1. For Braidwood Units 1 and 2: Perform corrective actions to re-establish periodic eddy current testing of the flux thimble tubes prior to the period of extended operation to ensure that wall thickness is monitored to detect loss of material from the flux thimble tubes. Once periodic eddy current testing is re-established, eddy current testing will be performed for each flux thimble tube every refueling outage until sufficient data has been accumulated to establish a plant-specific eddy current testing frequency to ensure that no flux thimble tube is predicted to incur wear that exceeds 80% before the next inspection. Flux thimble tube wall thickness measurements will be trended and wear rates will be calculated based on plant-specific data. Wall thickness will be projected using plant-specific data in accordance with the WCAP-12866, "Bottom Mounted Instrumentation Flux Thimble Wear," methodology.

2. For Braidwood Unit 1:

   a. The 17 Braidwood Station, Unit 1 flux thimble tubes that exhibited indications of wear during eddy current testing performed during A1R15 Refueling Outage (Fall 2010), will be replaced or removed from service during A1R18 Refueling Outage (Spring 2015), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program. (Flux thimble tubes 1(J-8), 8(K-6), 9(H-11), 12(E-9), 14(H-4), 18(L-11), 19(L-5), 21(E-11), 23(D-10), 36(J-14), 37(P-9), 41(N-4), 44(R-8), 45(N-13), 48(P-4), 54(A-11), 55(N-14))

b. The remaining Braidwood Station, Unit 1 flux thimble tubes, not replaced during A1R18, will be replaced or removed from service during A1R19 Refueling Outage (Fall 2016), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program.

c. Following A1R19, any Braidwood Station, Unit 1 flux thimble tube will be replaced every two (2) refueling outages or removed from service if eddy current data is not obtained in accordance with the Flux Thimble Tube Inspection program.

3. For Braidwood Unit 2:

a. The 29 Braidwood Station, Unit 2 flux thimble tubes that exhibited indications of wear during eddy current testing performed during A2R15 Refueling Outage (Spring 2011) and not replaced during A2R17 Refueling Outage (Spring 2014), will be replaced or removed from service during A2R18 Refueling Outage (Fall 2015), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program. (Flux thimble tubes 1(J-8), 4(H-6), 5(F-8), 6(J-10), 7(F-7), 9(H-11), 10(L-8), 11(G-5), 18(L-11), 22(K-12), 23(D-10), 24(H-13), 25(N-8), 26(H-3), 27(C-8), 29(N-6), 32(L-13), 33(C-5), 34(H-2), 36(J-14), 37(P-9), 40(F-14), 41(N-4), 42(D-3), 45(N-13), 46(J-1), 50(R-6), 52(L-15), 56(N-2))

b. The remaining Braidwood Station, Unit 2 flux thimble tubes, not replaced during A2R17 or A2R18, will be replaced or removed from service during A2R19 Refueling Outage (Spring 2017), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program.

c. Following A2R19, any Braidwood Station, Unit 2 flux thimble tube will be replaced every two (2) refueling outages or removed from service if eddy current data is not obtained in accordance with the Flux Thimble Tube Inspection program.

These enhancements will be implemented in accordance with the schedule specified in the enhancement.

A.2.1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new condition monitoring program that directs visual inspections of internal surfaces of components within the scope of license renewal be performed when they are made accessible during periodic system and component surveillances or during the performance of maintenance activities. The program provides assurance that existing environmental conditions are not causing material degradation that could result in loss of intended function.

This opportunistic approach is supplemented to ensure a representative sample of components within the scope of this program are inspected. At a minimum, in each 10-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each 10-year period despite meeting the sampling minimum requirement.

The program consists of visual inspections of the internal surfaces of metallic components such as piping, piping elements and piping components, ducting components, tanks, heat exchangers, and other components that are exposed to air-indoor uncontrolled, diesel exhaust, condensation, and any water system other than open-cycle cooling water system, closed treated water system, and fire water system. During these inspections, the internal coatings of components are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. The program also consists of visual inspections of the internal surfaces of elastomeric components that are exposed to condensation, treated water, fuel oil, and lubricating oil augmented by physical manipulation or pressurization to detect hardening or loss of strength where appropriate. The program will manage the aging effects of loss of material, reduction of heat transfer, and cracking for metallic components. The program will also manage the aging effects of loss of material and hardening and loss of strength for elastomeric components. The program will also manage the aging effect of loss of coating integrity for metallic components with internal linings or coatings. The program includes provisions for visual inspections of the internal surfaces of components not managed under other aging management programs.

This new aging management program will be implemented prior to the period of extended operation.

A.2.1.26 Lubricating Oil Analysis

The Lubricating Oil Analysis aging management program is an existing preventive and mitigative program that ensures that the oil environment in the mechanical systems is maintained to the required quality to prevent or mitigate age-related degradation of components within the scope of this program. The Lubricating Oil Analysis program ensures that oil systems are maintained free of contaminants (primarily water and particulates), thereby, preserving an environment that is not conducive to loss of material or reduction of heat transfer in piping, piping components, piping elements, valve bodies, pump casings, gear boxes, tanks, and heat exchangers exposed to an oil environment. Testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of oil contaminants (e.g., water or particulates) may also indicate in-leakage and corrosion product buildup. Loss of coating integrity for coated or lined components within the scope of this program will be detected by the presence of particulates in the oil. In addition, the differential pressure across the safety injection pump lubricating oil system oil filter is measured. These readings would provide indication if any significant degradation of the safety injection pump lubricating oil reservoir coating were to occur and cause coating debris to enter the lubricating oil system.

A.2.1.27 Monitoring of Neutron-Absorbing Materials Other than Boraflex

The Monitoring of Neutron-Absorbing Materials Other than Boraflex aging management program is an existing condition monitoring program that periodically inspects and analyzes test coupons of the Boral material in the spent fuel storage racks to determine if the neutron-absorbing capacity of the material has degraded over time. This program ensures that a five (5) percent sub-criticality margin in the spent fuel pool is maintained during the period of extended operation by monitoring for loss of material, changes in dimension, and loss of neutron-absorption capacity of the Boral material. The existing coupon inspection frequency ensures at least one (1) coupon is examined during each 10 year period, beginning 10 years prior to the period of extended operation.

The Monitoring of Neutron-Absorbing Materials Other than Boraflex aging management program will be enhanced to:

1. Maintain the coupon exposure such that it is bounding for the Boral material in all spent fuel racks prior to coupons being examined, by ensuring that the coupons have been surrounded with a greater number of freshly discharged fuel assemblies than that of any other cell location.

This enhancement will be implemented prior to the period of extended operation.

A.2.1.28 Buried and Underground Piping

The Buried and Underground Piping aging management program is an existing preventive, mitigative, and condition monitoring program that manages the external surface aging effects for buried and underground piping. The program manages aging through preventive, mitigative (e.g., coatings, backfill quality, and cathodic protection), and inspection activities for piping and components within the scope of license renewal. It manages the aging effects of loss of material at Byron and Braidwood Stations, as well as cracking and change in material properties (e.g., cracking, blistering, and change in color) at Braidwood Station only.

External inspection of buried components will occur opportunistically when they are excavated for any reason.

The Buried and Underground Piping aging management program will be enhanced to:

1. Perform manual examinations, in addition to visual inspections, to detect hardening, softening, or other changes in material properties for buried polymeric piping (Braidwood only).

2. Cracking will be managed for stainless steel components, utilizing a method that has been demonstrated to be capable of detecting cracking, whenever coatings are removed and expose the base material (Braidwood only).

3. Ensure all underground carbon steel essential service water system piping within the scope of license renewal is coated in accordance with NACE SP0169-2007 prior to the period of extended operation (Byron only).

4. Direct visual inspections of coated piping and components will be performed by an individual possessing a NACE Coating Inspector Program Level 2 or 3 operator qualification, or by an individual who has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course.

5. Inspection quantities of buried piping within the scope of license renewal will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4a, and based upon the as-found results of cathodic protection system availability and effectiveness during each 10 year period, beginning 10 years prior to the period of extended operation.

6. The buried carbon steel condensate system piping within the scope of license renewal will be addressed, through means of a long term mitigation strategy, prior to entering the period of extended operation. Mitigation may include activities such as fully recoating, complete replacement with like or upgraded material, installation of internal polymeric sleeves, and routing of pipe above ground or in an engineered trench for leak detection. Inspections of the condensate system piping will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4a, and based on the mitigation strategy implemented (Braidwood only).

7. Inspection quantities of underground piping within the scope of license renewal will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4b, during each 10 year period, beginning 10 years prior to the period of extended operation.

   a. The piping and components inside the Byron 0SX138A and 0SX138B valve vaults will be visually inspected by engineering on a quarterly basis until either measures to prevent immersion of the piping and components inside the vault are implemented, or a coating system is installed that is designed for periodic immersion applications (Byron only).

8. If adverse indications are detected during inspection, inspection sample sizes within the affected piping categories will be doubled. If adverse indications are found in the expanded sample, an analysis will be conducted to determine the extent of condition and extent of cause. The size of the follow-on inspections will be determined based on the analysis. Timing of the additional inspections will be based on the severity of the identified degradation and the consequences of leakage. In all cases, the additional inspections will be performed within the same 10-year inspection interval in which the original adverse indication was identified. Expansion of sample size may be limited by the extent of piping subject to the observed degradation mechanism.

9. In performing cathodic protection surveys, only the -850mV polarized potential criterion specified in NACE SP0169-2007 for steel piping will be used for acceptance criteria and determination of cathodic protection system effectiveness. Alternatively, soil corrosion, or electric resistance, probes may also be used to demonstrate cathodic protection effectiveness during the annual surveys. An upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes will also be established, so as to preclude potential damage to coatings.

10. An extent of condition evaluation will be conducted if observed coating damage caused by non-conforming backfill has been evaluated as significant. The extent of condition evaluation will be conducted to ensure that the as-left condition of backfill in the vicinity of the observed damage will not lead to further degradation.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.29 ASME Section XI, Subsection IWE

The ASME Section XI, Subsection IWE aging management program is an existing program based on ASME Section XI, Subsection IWE requirements and complies with the provisions of 10 CFR 50.55a. This program is in accordance with ASME Section XI, Subsection IWE, 2007 Edition through the 2008 Addenda at Byron and the 2013 Edition at Braidwood.

The program consists of periodic visual and volumetric examination of pressure retaining components of steel and concrete containments for signs of degradation, assessment of damage, and corrective actions. The program includes aging management of surfaces and components such as bolting for containment closure, containment liner, containment penetrations (electrical, instrumentation, and control assemblies), mechanical penetrations, penetration bellows at the containment boundary, penetration sleeves at the containment boundary, and the personnel airlock and equipment hatch. The moisture barrier, which is a sealant between the bottom of the containment liner and the base mat, is included within the scope of the program.

Examination methods include visual and volumetric testing as required by ASME Section XI, Subsection IWE. Observed conditions that have the potential for impacting an intended function are evaluated for acceptability in accordance with ASME requirements and corrected in accordance with corrective action program.

The ASME Section XI, Subsection IWE aging management program will be enhanced to:

1. Provide guidance for specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting.

2. Use the condition of the embedded reinforcing steel at the inner surface of the tendon tunnel as a representative indicator for the potential for corrosion at the exterior surface of the containment liner plate. Use the results of Structures Monitoring (B.2.1.34) aging management program, Enhancement 16 activities and results from ongoing examinations of the tendon tunnel performed as part of the ASME

Section XI, Subsection IWL (B.2.1.30) and Structures Monitoring (B.2.1.34) aging management programs to identify changing conditions. Changing conditions consisting of the identification of significant corrosion of embedded steel in the tendon tunnel structure require an evaluation to determine if augmented examinations in accordance with requirements of IWE-1240 “Surface Areas Requiring Augmented Examination” are required due to the potential for accelerated corrosion at the exterior surface of the containment liner plate.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.30 <u>ASME Section XI, Subsection IWL</u>

The ASME Section XI, Subsection IWL aging management program is an existing program that consists of (a) periodic visual inspection of concrete surfaces for reinforced and unbonded, prestressed concrete containments, and (b) periodic visual inspection and sample tendon testing of unbonded post-tensioning systems for prestressed concrete containments for signs of degradation, assessment of damage, and corrective actions, and testing of the tendon corrosion protection medium and free water. Measured tendon lift-off forces are compared to predicted tendon forces calculated in accordance with RG 1.35.1.

Reinforced concrete surfaces are inspected for material degradation, including loss of material, cracking, increase in porosity and permeability, and loss of bond. A sample of each tendon wire type (vertical, hoop, dome) for the post-tensioning system is tested for loss of prestress. One tendon wire of each type is also examined for loss of material and subject to physical testing to determine yield strength, ultimate tensile strength, and elongation. The end anchorage for the unbonded post-tensioning system is inspected for loss of material.

This program is in accordance with ASME Section XI, Subsection IWL, 2007 Edition through the 2008 Addenda at Byron and the 2013 Edition at Braidwood, and complies with the provisions of 10 CFR 50.55a.

The ASME Section XI, Subsection IWL aging management program will be enhanced to:

1. Include additional augmented examination requirements after post-tensioning system repair/replacement activities in accordance with Table IWL-2521-2.

2. A one-time inspection of one (1) vertical and one (1) horizontal tendon on each unit will be performed prior to the period of extended operation. The inspection will consist of visually examining one (1) wire from each of the two (2) types of tendons at a worst-case location based on evidence of free water, grease

discoloration, and grease chemistry results. This location will serve as a leading indicator for potential degradation or tendon surface corrosion. The visual inspection of these wires will be performed in accordance with existing station procedures used for inspections consistent with IWL-2523.2. The acceptance criteria will consist of each wire being free of any active corrosion, including general and pitting corrosion. In the event that the acceptance criteria are not met and corrosion is identified, the condition will be entered into the corrective action program. The condition will be evaluated to characterize the corrosion, determine the cause of the corrosion, the location, depth, extent of the condition, and applicability of the condition to other wires that comprise that tendon. Corrective actions may include activities such as grease analysis, replacement of grease within the tendon duct, additional wire inspections from the same tendon, evaluation of the tendon capacity, potential replacement of the tendon, and augmented inspections and grease sampling of other leading indicator tendons, based, in part, on previous evidence of free water, observed grease leakage, grease discoloration, and grease chemistry results. Specific corrective actions will depend upon the cause, extent of condition, and grease properties. These corrective actions will be consistent with those actions which would be evaluated during periodic required IWL examinations (Braidwood only).

3. In order to monitor for tendon exposure to free water and moisture and manage any potential adverse effects, a periodic tendon water monitoring and grease sampling program will be implemented (Braidwood only). The program will consist of:

   a. A baseline inspection of tendon grease caps at the bottom of all vertical and dome tendons, as well as all below-grade horizontal tendons, prior to the period of extended operation. The baseline inspection will check for evidence of free water and grease discoloration, with further actions taken based on the condition of the grease.

   b. A follow-up tendon grease cap inspection of all vertical and dome tendons, as well as all below-grade horizontal tendons, will be performed within 10 years of the initial inspection, using the same approach as the baseline inspection.

c. For those tendons where free water, moisture, and grease did not meet acceptance criteria during the two (2) previous inspections, periodic monitoring of grease chemistry and moisture, free water, and grease discoloration will be performed on a frequency not to exceed 10 years. Tendons, which exhibit significant quantities of free water (e.g., more than eight ounces) during periodic monitoring, will be inspected more often, with the timing of follow-up inspections increased until a frequency is achieved that no longer results in significant amounts of free water observed during successive inspections. Tendon water inspection and draining frequencies may vary from annual to every ten (10) years, depending upon grease chemistry and moisture parameters meeting IWL acceptance criteria. The maximum ten (10) year periodic frequency is meant to address any tendons which exhibit evidence of free water but the quantity is observed to be insignificant, with no observable grease discoloration, and given that the tendon wasn’t inspected for at least ten (10) years prior. More frequent follow-up inspections will be performed for tendons which exhibit insignificant quantities of free water, but were inspected within the ten (10) years prior. In all cases, the frequency of inspections for water in individual tendons will be adjusted to be commensurate with the severity of the conditions found during each examination.

d. Braidwood has performed augmented inspections on additional tendons beyond those selected for the ASME Section XI, Subsection IWL program. The Braidwood augmented inspections are performed on a 5 year frequency, in conjunction with the ASME Section XI, Subsection IWL aging management program. The current augmented examinations of additional tendons will continue until the periodic tendon water monitoring and grease sampling program described above is implemented.

Corrective actions will be taken as necessary to ensure that the tendon grease meets ASME Section XI, Subsection IWL requirements.

4. Explicitly require that areas of concrete deterioration and distress be recorded in accordance with the guidance provided in ACI 349.3R. The visual resolution capability of direct and remote examination techniques will be sufficient to detect concrete degradation at the levels described in Chapter 5 of ACI 349.3R. The resolution capability of the optical aids used for remote examinations will be demonstrated as equivalent to direct visual examination.

5. Include quantitative acceptance criteria, based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R, that will be used to augment the qualitative assessment of the Responsible Engineer. In addition, the Responsible Engineer will confirm that the visual resolution capability used for the concrete Containment Structure examinations was sufficient to evaluate the examination results against the quantitative acceptance criteria described in Chapter 5 of ACI 349.3R.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.31 <u>ASME Section XI, Subsection IWF</u>

The ASME Section XI, Subsection IWF aging management program is an existing program that consists of periodic visual examinations of component supports, evaluation, and corrective actions. The scope of the program includes ASME Class 1, 2, 3, and MC piping and component supports and high-strength structural bolting. The supports are examined for signs of degradation such as loss of material, loss of mechanical function, and loss of pre-load. The program is implemented through corporate and station procedures, which provide inspection and acceptance criteria consistent with the requirements of the ASME Code, Section XI, Subsection IWF as approved in 10 CFR 50.55a. This program is in accordance with ASME Section XI, Subsection IWF, 2007 Edition through the 2008 Addenda at Byron and the 2013 Edition at Braidwood. The monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant degradation.

The ASME Section XI, Subsection IWF aging management program will be enhanced to:

6. Add the MC supports for the transfer tube in the refueling cavity in the Containment Structure and refueling canal in the Fuel Handling Building to the scope of the program.

7. Revise implementing documents to provide guidance for proper specification of bolting material, storage, lubricants and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Bolting material with actual measured yield strength of 150 ksi or greater shall not be used in plant changes without engineering approval, due to consideration of stress corrosion cracking vulnerability. Storage requirements for high strength bolts shall include the recommendations of the Research Council for Structural Connections, “Specification for Structural Joints Using ASTM A325 or A490 Bolts”, Section 2. Lubricants that contain molybdenum disulfide (MoS_2) shall not be applied to high strength structural bolts within the scope of

license renewal.

8. Provide procedural guidance, regarding the selection of supports to be inspected on subsequent inspections, when a support is repaired in accordance with the corrective action program. The enhanced guidance will ensure that the supports inspected on subsequent inspections are representative of the general population.

9. Perform one-time volumetric examinations on a sample of ASTM A490 bolts, greater than one-inch nominal diameter for the detection of stress corrosion cracking prior to the period of extended operation. Volumetric examinations will be performed in accordance with the requirements of ASME Code Section XI, Appendix VIII, Supplement 8. The sample will consist of bounding and representative A490 bolt sizes, joint configurations, and environmental exposure conditions. The sample will consist of 20% of the ASTM A490 bolts greater than one-inch nominal diameter or a maximum of 25 ASTM A490 bolts total for both Byron and Braidwood stations. The selection of the samples will consider susceptibility to stress corrosion cracking (e.g., actual measured yield strength) and ALARA principles. Any adverse results of the volumetric examinations will be entered into the corrective action program and will be evaluated by engineering to determine if additional actions are warranted such as expansion of sample size, scope, and frequency of any additional supplemental visual or volumetric examinations, as well as any code requirements specified by ASME Section XI, Subsection IWF. Specifically, the implementing documents for performing the one-time volumetric examinations will contain criteria for extending the ASTM A490 bolt examination scope to other ASTM A490 bolts used in similar joint configurations and environmental exposure conditions if the volumetric examination of an ASTM A490 bolt shows adverse results, which is similar to the methodology used by the ASME Code IWF-2430 for IWF component supports. In addition, the program will be revised to include periodic volumetric examinations of ASTM A490 bolts in sizes greater than one-inch nominal diameter, if the one-time volumetric examination of an ASTM A490 bolt shows signs of cracking. The periodic examinations of the ASTM A490 bolts are included in the periodic examination of the supports. For the periodic examinations of supports, the population of the supports examined is specified in Table IWF-2500-1. Consistent with the GALL Report, the periodic examinations will include volumetric examinations of high-strength bolts to detect cracking, if required, in addition to the VT-3 examinations of the high-strength bolts.

10. Revise implementing documents to perform periodic visual examinations to detect a corrosive environment that supports SCC potential for all (100%) of high strength bolting greater than one-inch nominal diameter prior to the period of extended operation, and then each inspection interval of 10 years thereafter. The periodic visual examinations will include criteria to identify if the bolting has been exposed to moisture or other contaminants by evidence of moisture, residue, foreign substance, or corrosion. Adverse conditions identified during the examinations will be evaluated by engineering to determine if the bolt has been exposed to a corrosive environment with the potential to cause SCC. The bolts determined to have been exposed to corrosive environment with the potential to cause SCC will be included in a sample population for each specific bolt material where SCC is a concern. A sample size equal to 20 percent (rounded up to the nearest whole number) of the bolts in the sample population, with a maximum sample size of 25 bolts will be subject to supplemental volumetric examination to determine if SCC is present. The selection of the samples will consider susceptibility to stress corrosion cracking (e.g., actual measured yield strength) and ALARA principles. Volumetric examinations will be performed in accordance with the requirements of ASME Code Section XI, Appendix VIII, Supplement 8. The results of the volumetric examinations will be evaluated by engineering to determine if additional actions are warranted such as expansion of sample size, scope, and frequency of any additional supplemental visual or volumetric examinations, as well as any code requirements specified by ASME Section XI, Subsection IWF.

11. Add the control rod drive mechanism seismic support assembly to the scope of the program to implement additional examinations.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.32 <u>10 CFR Part 50, Appendix J</u>

The 10 CFR Part 50, Appendix J aging management program is an existing performance monitoring program that monitors leakage rates through the containment pressure boundary, including the containment liner, associated welds, penetrations, fittings, and other access openings, in order to detect degradation of the containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. The Primary Containment Leakage Rate Testing Program (LRT) provides for aging management of pressure boundary degradation for electrical penetration assemblies, mechanical penetrations, penetration bellows and sleeves, the containment liner, bolting, personnel airlock, equipment hatch, and seals, gaskets, and moisture barriers, due to aging effects from the loss of material, loss of sealing, loss of leaktightness, loss of preload, or cracking in systems penetrating containment. Consistent with the current licensing basis, the containment leak rate tests are performed in accordance with the regulations and guidance provided in 10 CFR Part 50, Appendix J, Option B; Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program"; NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J,"; and ANSI/ANS 56.8, "Containment System Leakage Testing Requirements."

A.2.1.33 Masonry Walls

The Masonry Walls program is an existing program implemented as part of the Structures Monitoring (A.2.1.34) program. Masonry wall condition monitoring is based on guidance provided in IE Bulletin 80-11, "Masonry Wall Design," and NRC Information Notice 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11," and is implemented through station procedures.

The Masonry Walls aging management program addresses loss of material, and cracking due to age-related degradation of masonry walls and will inspect for shrinkage or separation, along with gaps between the supports and masonry walls. The program relies on periodic visual inspections, conducted at a frequency not to exceed five years, to monitor and maintain the condition of masonry walls within the scope of license renewal. Masonry walls that are considered fire barriers are also managed by the Fire Protection (A.2.1.15) program.

The Masonry Walls aging management program will be enhanced to:

1. Add masonry walls in the following structures to the program scope:

    a. Radwaste and Service Building Complex

        i. Radwaste Building

        ii. Original Service Building

    b. Turbine Building Complex

    c. Switchyard Structures

        i. Relay House

2. Provide additional guidance for inspection of masonry walls for shrinkage, separation, and for gaps between the supports and the masonry walls that could impact the intended function of the masonry walls.

3. Require that personnel performing inspections and evaluations meet the qualifications described in ACI 349.3R.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.34 Structures Monitoring

The Structures Monitoring program is an existing program that was developed to implement the requirements of 10 CFR 50.65 and is based on NUMARC 93-01, Rev. 2 "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and Regulatory Guide 1.160, Rev. 2 "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The program includes elements of the Masonry Walls (A.2.1.33) program. The program relies on periodic visual inspections and monitoring of the condition of structures and structural components, structural bolting, component supports, and masonry block walls to ensure that aging degradation leading to loss of intended functions will be detected and that the extent of degradation can be determined. The inspections are conducted on a frequency not to exceed five (5) years.

The Structures Monitoring aging management program will be enhanced to:

1. Add the following structures;
    a. Radwaste and Service Building Complex
        i. Radwaste Building
        ii. Original Service Building
    b. Turbine Building Complex
    c. Yard Structures
        i. Transformer foundations
        ii. Valve and line enclosures
    d. Fire protection structures-features
        i. Transformer fire barrier walls
        ii. Fuel oil storage tank berm
    e. Containment structure features
        i. Containment access facility hallway
2. Add the following components and commodities;
    a. Blowout panels
    b. Building features – doors and seals, bird screens, louvers, windows

c. Compressible joints and seals, gaskets and moisture barriers

d. Concrete curbs

e. Electrical cable trays, conduits and tube tracks

f. Hatches and plugs

g. Insulation including jacketing

h. Manholes, handholes and duct banks

i. Metal components, including metal decking for concrete slabs, miscellaneous steel, sump screens and trench covers, and scuppers around the spent fuel pool

j. New fuel storage racks

k. Offgas stack and flue

l. Panels, racks, cabinets, and other enclosures

m. Penetration seals and sleeves

n. Pipe whip restraints, jet impingement shields, and spray shields

o. Pipe, electrical and equipment component support members

p. Sliding surfaces

q. Spent fuel pool gates

r. Sumps and liners

3. Monitor groundwater chemistry on a frequency not to exceed five (5) years for pH, chlorides, and sulfates and evaluate results exceeding the threshold criteria to assess impact, if any, on below grade concrete.

4. Based on groundwater chemistry monitoring results, select and inspect every five (5) years a structure that will be used as a leading indicator for the condition of below grade concrete exposed to groundwater.

5. Require (a) evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examination of representative samples of the exposed portions of the below grade concrete, when excavated for any reason.

6. Provide guidance for proper specification of high strength bolting material and lubricant to prevent or mitigate degradation and failure of structural bolting.

7. Revise storage requirements for high strength bolts to include recommendations of Research Council on Structural Connections (RCSC) Specification for Structural Joints Using High Strength Bolts, Section 2.0.

8. Clarify that loose bolts and nuts, and cracked high strength bolts are not acceptable unless accepted by engineering evaluations.

9. Include the potential for reduction in concrete anchor capacity due to local concrete degradation.

10. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R with respect to knowledge of in-service inspection of concrete and visual acuity requirements.

11. Require acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R.

12. Perform inspection of elastomeric components such as vibration isolation elements and structural seals for cracking, loss of material and hardening. Visual inspections of elastomeric components are to be supplemented by feel or manipulation to detect hardening.

13. Monitor accessible sliding surfaces to detect loss of mechanical function or significant loss of material due to wear, corrosion, debris, dirt, distortion, or overload that could restrict or prevent sliding of surfaces as required by design.

14. Formalize requirements for the monitoring of the leak detection sight glasses associated with the refuel cavity, transfer canal, spent fuel pool, and refueling water storage tank on a periodic basis.

15. Require visual inspections of submerged concrete structural elements by dewatering a structure or by a diver if the structure is not dewatered at least once every five (5) years (Byron only).

16. At each site, perform one-time sampling activities on below grade, reinforced concrete at specific locations in the tendon tunnels. Select the locations exhibiting significant mineral deposits to serve as

leading indicators for potential reinforced concrete degradation as a result of exposure to ground water in-leakage and build-up of mineral deposits. Take corrective actions, if necessary, prior to the period of extended operation. Perform the one-time sampling activities as follows:

a. Obtain water in-leakage samples, at representative locations with mineral deposits due to water in-leakage, and analyze for pH, chlorides, sulfates, minerals, and iron content.

b. Obtain representative mineral deposit samples and analyze for chemical composition.

c. Remove three concrete core samples.

   i. Test two of the concrete core samples for compressive strength and perform petrographic examination of the core samples. Select representative locations for the concrete core samples that include one with significant mineral deposits and another at a location with no mineral deposits for comparative purposes.

   ii. Drill an additional core at a crack with significant mineral deposits and subject the core to petrographic examination.

d. Expose and examine reinforcing steel at two locations, with water in-leakage, cracks, and significant mineral deposits.

e. Collectively evaluate the results from the water in-leakage analysis, the chemical composition of the mineral deposits, examination of the exposed reinforcing steel, and the core sample testing to confirm there is no significant degradation to the reinforced concrete material properties and to determine if additional corrective actions are necessary. Additional corrective actions may include, but are not limited to, an extent of condition review for other potentially impacted structures, more frequent examinations, and additional sampling and analysis, as appropriate.

17. Perform visual inspections of polymeric components, such as blowout panels, for changes in material properties. Observations of material discoloration, cracking, crazing, and loss of material will provide visual indications of changes in material properties prior to a loss of component intended function.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.35 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, aging management program is an existing condition monitoring program that consists of inspection and surveillance programs to provide management of aging effects for slopes, cooling pond, intake structure, and other water control structures associated with emergency cooling water systems or flood protection based on RG 1.127, Rev. 1. There are no dams or canals within the scope of the program. The program monitors the condition of the River Screen House and Essential Service Water Cooling Towers at Byron, and the Essential Service Cooling Pond and Lake Screen Structures at Braidwood. In addition to reinforced concrete and earthen structures, the program also includes structural steel, structural bolting, miscellaneous steel components (trash rack bars) associated with the water control structures, and cooling tower fill and drift eliminators associated with the Essential Service Water Cooling Towers. The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, aging management program addresses age-related deterioration, degradation due to extreme environmental conditions, and the effects of natural phenomena that may affect the intended function of the water-control structures. The program is used to manage conditions such as, loss of material, cracking, loss of bond, increase in porosity and permeability, change in material properties, reduction in heat transfer, loss of strength, or loss of form. The inspection of the water-control structures are performed at intervals no more than five (5) years. Elements of the program are designed to detect degradation and take corrective actions to prevent the loss of an intended function.

The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, Program will be enhanced to:

1. Provide guidance for specification of structural bolting material, and bolting lubricants to prevent or mitigate degradation and failure of structural bolting.

2. Revise storage requirements for structural bolting to include recommendations of Research Council on Structural Connections (RCSC) Specification for Structural Joints Using High Strength Bolts, Section 2.0.

3. Include the potential for reduction in concrete anchor capacity due to local concrete degradation.

4. Include all aging affects addressed by ACI 349.3R in procedures and require acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R.

5. Clarify that loose bolts and nuts, and cracked bolts are not acceptable unless accepted by engineering evaluations.

6. Require that steel components subject to RG 1.127 are inspected for loss of material.

7. Require that inspectors work under the direction of a qualified engineer for submerged concrete inspections.

8. Require special inspections also be performed in the event of large floods, hurricanes, and intense local rainfalls.

9. Require increased inspection frequency if the extent of the degradation is such that the structure or component may not meet its design basis if allowed to continue uncorrected until the next normally scheduled inspection.

10. Require (a) evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examination of representative samples of the exposed portions of the below grade concrete, when excavated for any reason.

11. Monitor raw water and groundwater chemistry at least once every five (5) years for pH, chlorides, and sulfates and verify that it remains non-aggressive, or evaluate results exceeding criteria to assess impact, if any, on submerged concrete.

12. Based on groundwater chemistry monitoring results, select and inspect every five (5) years a structure that will be used as a leading indicator for the condition of below grade concrete exposed to groundwater.

13. Require visual inspections of submerged concrete structural components by dewatering a structure or by a diver if the structure is not dewatered at least once every five (5) years. Maintenance procedures will be enhanced to require opportunistic inspection of submerged concrete structures when they are dewatered and made accessible.

14. Require that degraded conditions be documented and trended until the condition is no longer occurring or until a corrective action is implemented.

15. Clarify parameters to be monitored and inspected at the Essential Service Water Cooling Towers to include visual inspection for loss of material and reduction of heat transfer for the cooling tower fill, and visual inspection with physical manipulation for change in material properties associated with the PVC drift eliminators and fiberglass support beams for the drift eliminators (Byron only).

16. Manage the condition of the Byron Essential Service Water Cooling Towers (SXCTs) as follows:

    a. Monitor and trend inspection activities at the SXCTs on an increased frequency, with inspections of the entire tower, including inspections of the fill support beams and air-inlet framing, on a three (3) year interval. The recommendations in Chapter 5 of ACI 349.3R will be used for quantitative acceptance and evaluation criteria.

    b. Develop a repair plan to address degradation of the SXCTs with specific emphasis and consideration for the fill support beams. Repairs that are required will be scheduled based on a ranking of the condition observed and the potential for the degradation to progress or propagate.

The Byron Essential Service Water Cooling Tower inspection and maintenance plan was initiated prior to receipt of the renewed licenses, and will continue through the period of extended operation to ensure the condition of the SXCT is maintained. The remainder of the enhancements will be implemented prior to the period of extended operation.

A.2.1.36 <u>Protective Coating Monitoring and Maintenance Program</u>

The Protective Coating Monitoring and Maintenance Program is an existing condition monitoring program that provides for aging management of Service Level I coatings inside BBS containments including selection, application, inspection, and maintenance. The program is comparable to RG 1.54, Revision 2. The failure of the Service Level I coatings could adversely affect the operation of the Emergency Core Cooling Systems (ECCS) by clogging the ECCS suction strainers. Proper maintenance of the Service Level I coating ensures that coating degradation will not impact the operability of the ECCS systems. The program includes a visual examination of all reasonably accessible Service Level 1 coatings inside containment during every refueling outage and includes assessment and repair for any condition that adversely affects the intended function of Service Level I coatings.

Service Level I coatings will prevent or minimize the loss of material due to corrosion but these coatings are not credited for managing the effects of corrosion for the carbon steel containment liners and components at BBS. This program ensures that the Service Level I coatings maintain adhesion so as to not affect the intended function of the ECCS suction strainers.

The program also provides controls over the amount of unqualified coating which is defined as coating inside the containment that has not passed the required laboratory testing, including irradiation and simulated Design Basis Accident (DBA) conditions. Unqualified coating may fail in a way to affect the intended function of the Emergency Core Cooling Systems (ECCS) suction strainers. Therefore, the quantity of unqualified coating is controlled to ensure that the amount of unqualified coating in the containment is kept within acceptable design limits.

The Protective Coating Monitoring and Maintenance Program aging management program will be enhanced to:

1. Add recurring work orders requiring Service Level I coating inspections every refuel outage.

2. Require qualification of coating inspectors to ASTM D 5498.

3. Require qualification of personnel in accordance with ASTM D 7108.

4. Incorporate guidance for inspection and maintenance of Service Level I coatings per Regulatory Guide 1.54 and impose ASTM D 5163-08 requirements for Service Level I coatings condition assessment, reporting, evaluation, and documentation.

5. Require thorough visual inspections of all coatings near sumps or screens associated with the Emergency Core Cooling System (ECCS) by the coatings inspector(s).

6. Specify instruments and equipment that may be needed for Service Level I coatings inspections.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.37 Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new program that will be used to manage aging of the insulation material for non-EQ cables and connections during the period of extended operation. Accessible cables and connections located in adverse localized environments will be visually inspected at least once every 10 years for cable jacket and connection insulation surface anomalies such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination, that could indicate incipient conductor insulation aging degradation from temperature, radiation, or moisture. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable or connection.

This new program will be implemented prior to the period of extended operation. In addition, the first inspections will be completed prior to the period of extended operation.

A.2.1.38 Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

The Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program reviews calibration results or findings of surveillance tests on electrical cables and connections used in circuits with sensitive, high-voltage, low-level current signals to provide an indication of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance.

The in-scope instrumentation circuits include the following:

a. Portions of the Radiation Monitoring System:

    1. Fuel handling incident area radiation monitors

    2. Control Area Ventilation System control room outside air intake and control room turbine building air intake radiation monitors

    3. Main steam line and piping penetration area radiation monitors

    4. Auxiliary Building vent stack wide range gas monitor

b. Portions of the Reactor Protection System:

    1. Source range / intermediate range neutron monitors (SR/IR) (Braidwood only)

The source range / intermediate range neutron monitors at Byron are included in the scope of the EQ program. The power range neutron monitors at Byron and Braidwood are included in the scope of the EQ program.

Calibration testing will be performed for the in-scope circuits when the cables are included as part of the calibration circuit. By reviewing the results obtained during normal calibration or surveillance, severe aging degradation may be detected prior to the loss of the cable and connection intended function. The review of calibration results or findings of surveillance tests will be performed at least once every 10 years. A proven cable test (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation condition) will be performed in cases where cables are not included as part of the calibration or surveillance program testing circuit. The test frequency is based on engineering evaluation and will be at least once every 10 years.

This new program will be implemented prior to the period of extended operation. In addition, the first review of the calibration results or findings of surveillance test results or cable tests for license renewal will be completed prior to the period of extended operation.

A.2.1.39 Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program calls for inaccessible or underground (e.g. in conduit, duct bank, or direct buried) power (greater than or equal to 400 volts) cables exposed to significant moisture to be tested at least once every six (6) years to provide an indication of the condition of the conductor insulation. Significant moisture is defined as periodic exposure to moisture that lasts more than a few days (e.g., cable wetting or submergence in water). Periodic exposures that last less than a few days (e.g., normal rain and drain) are not significant. More frequent testing may occur based on test results and operating experience. The first tests will be completed prior to the period of extended operation. The specific type of test to be used should be capable of detecting reduced insulation resistance of the cable’s insulation system due to wetting or submergence. The condition of the cable insulation can be assessed with reasonable confidence using one or more of the following techniques: Dielectric Loss (Dissipation Factor/Power Factor), AC Voltage Withstand, Partial Discharge, Step Voltage, Time Domain Reflectometry, Insulation Resistance and Polarization Index, Line Resonance Analysis, or other testing that is state-of-the-art at the time the tests are performed. One (1) or more tests may be used to determine the condition of the cables so they will continue to meet their intended function during the period of extended operation.

The inspection frequency for water collection is established based on plant-specific operating experience with cable wetting or submergence in manholes (i.e., the inspection is performed periodically based on water accumulation over time and event driven occurrences such as heavy rain or flooding). The periodic inspection occurs at least annually. The inspection includes direct observation that cables are not wetted or submerged, that cables/splices and cable support structures are intact, and, if installed, dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. In addition, dewatering devices, if installed, are inspected and operation verified prior to any known or predicted heavy rain or flooding events.

This new program will be implemented prior to the period of extended operation. In addition, the first cable tests and first manhole inspections for license renewal will be completed prior to the period of extended operation.

A.2.1.40 Metal Enclosed Bus

The Metal Enclosed Bus aging management program is an existing program that calls for the visual inspection of metal enclosed bus (MEB) internal surfaces to detect age-related degradation, including cracks, corrosion, foreign debris, excessive dust buildup, and evidence of moisture intrusion. MEB insulating material is visually inspected for signs of embrittlement, cracking, chipping, melting, swelling, discoloration, or surface contamination, which may indicate overheating or aging degradation. The internal bus insulating supports are visually inspected for structural integrity and signs of cracks. MEB external surfaces are visually inspected for loss of material due to general, pitting, and crevice corrosion. Accessible elastomers (e.g., gaskets, boots, and sealants) are inspected for degradation, including surface cracking, crazing, scuffing, and changes in dimensions (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening and loss of strength. A sample of accessible bolted connections is inspected for increased resistance of connection by measuring connection resistance using a micro-ohmmeter. These inspections are performed at least once every 10 years.

The Metal-Enclosed Bus aging management program will be enhanced to:

1. Specify that a sample size of 20 percent of the accessible bolted connection population with a maximum sample size of 25 to be inspected for increased resistance of connection by measuring the connection resistance using a micro-ohmmeter.

2. Specify that the external surfaces of metal enclosed bus enclosure assemblies are to be inspected for loss of material due to general, pitting, and crevice corrosion.

3. Specify maximum allowed bus connection resistance values.

These enhancements will be implemented prior to the period of extended operation.

A.2.1.41 Fuse Holders (Byron Only)

The Fuse Holders (Byron Only) aging management program is a new program that consists of fuse holders within the scope of license renewal located outside of active devices that are susceptible to increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent manipulation, or vibration. These fuse holders are tested by a proven test methodology at least once every 10 years to provide an indication of the condition of the metallic clamp portion of the fuse holders. Testing may include thermography, contact resistance testing, or other appropriate testing methods.

This new program will be implemented at Byron prior to the period of extended operation. In addition, the first tests for license renewal will be completed prior to the period of extended operation.

No fuse holders at Braidwood are required to be managed by this aging management program because there are no in-scope fuse holders located outside of active devices that are susceptible to aging effects at Braidwood.

A.2.1.42 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program. The program consists of a representative sample (20 percent with a maximum sample size of 25) of electrical connections within the scope of license renewal, which is tested at least once prior to the period of extended operation to confirm that there are no aging effects requiring management during that period. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation, such as heat shrink tape, sleeving, insulating boots, etc. The one-time test provides additional confirmation to support industry operating experience that shows that electrical connections have not experienced a high degree of failures and that existing installation and maintenance practices are effective.

This new aging management program and one-time tests will be implemented prior to the period of extended operation.

A.2.2 Plant-Specific Aging Management Programs

None. The Byron and Braidwood Stations, Units 1 and 2 License Renewal Application does not include plant-specific aging management programs.

A.3.0 NUREG-1801 Chapter X Aging Management Programs

A.3.1 Evaluation of Chapter X Aging Management Programs

Aging Management Programs evaluated in Chapter X of NUREG-1801 are associated with Time-Limited Aging Analysis for metal fatigue of the reactor coolant pressure boundary, concrete containment tendon prestress, and environmental qualification (EQ) of electric components. These programs are evaluated in this section.

A.3.1.1 Fatigue Monitoring

The Fatigue Monitoring aging management program is an existing preventive program that manages cumulative fatigue damage of the reactor pressure vessel (RPV) components, reactor coolant pressure boundary piping components, and other components. The Fatigue Monitoring aging management program manages fatigue of piping, piping elements, piping components, bolting, reactor vessels, reactor vessel internals, supports, heat exchangers and other components.

The Fatigue Monitoring aging management program monitors and tracks critical thermal, pressure, and seismic transients to ensure each analyzed component does not exceed the number of allowable cycles, thus ensuring that the cumulative usage factor (CUF) for each analyzed component does not exceed the design limit of 1.0 through the period of extended operation. The Fatigue Monitoring program also monitors and tracks other design basis events such as LOCAs. The number of allowable cycles is based on the design fatigue analyses transient inputs. The program requires comparison of the actual operational transient parameters to the applicable design transient definitions to assure the actual operational transients are bounded. If an allowable cycle limit is approached or the severity of an actual operational transient is not bounded by the applicable design transient definition, then this condition is entered into and addressed within the corrective action program to ensure that the design CUF limit is not exceeded.

The Fatigue Monitoring aging management program will be enhanced to:

1. Address the cumulative fatigue damage effects of the reactor coolant environment on component life by evaluating the impact of the reactor coolant environment on critical components for the plant identified in NUREG/CR-6260. Additional plant-specific component locations in the reactor coolant pressure boundary will be evaluated if they are more limiting than those considered in NUREG/CR-6260.

2. Monitor and track additional plant transients that are significant contributors to component fatigue usage.

3. Evaluate the effects of the reactor coolant system water environment on the reactor vessel internal components with existing fatigue CUF analyses to satisfy the evaluation requirements of ASME Code, Section III, Subsection NG-2160 and NG-3121.

4. Increase the scope of the program to include transients used in the analyses for ASME Section III fatigue exemptions, the allowable stress analyses associated with ASME Section III and ANSI B31.1, and the flaw evaluation analyses performed in accordance with ASME Section XI, IWB-3600.

These enhancements will be implemented prior to the period of extended operation.

A.3.1.2 Concrete Containment Tendon Prestress

The Concrete Containment Tendon Prestress aging management program is an existing program that is part of Byron and Braidwood Station’s Containment inservice inspection program that is based on ASME Section XI, Subsection IWL criteria, as supplemented by the requirements of 10 CFR 50.55a(b)(2)(viii). The program monitors and manages the loss of tendon prestress in the concrete containment prestressing system for the period of extended operation. The Concrete Containment Tendon Prestress aging management program requires periodic inspection of a sample of tendons during each inspection interval to confirm that individual and group tendon values meet ASME Section XI, Subsection IWL, acceptance criteria. Trending of individual measured tendon prestressing values for each tendon group is accomplished through a regression analysis, consistent with NRC Information Notice (IN) 99-10 guidelines. In accordance with the requirements of ASME Section XI, Subsection IWL, an evaluation will be performed if the tendon prestressing force trend lines predict the prestressing forces in the containment will fall below the minimum required value (MRV) prior to the next scheduled surveillance.

The Concrete Containment Tendon Prestress aging management program will be enhanced to:

1. For each surveillance interval, the predicted lower-limit, minimum required value, and trending lines will be developed for the period of extended operation as part of the regression analysis for each tendon group.

This enhancement will be implemented prior to the period of extended operation.

A.3.1.3 Environmental Qualification (EQ) of Electric Components

The Environmental Qualification (EQ) of Electric Components is an existing program that manages the aging of electrical equipment within the scope of 10 CFR 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants." The program establishes, demonstrates, and documents the level of qualification, qualified configurations, maintenance, surveillance, and replacements necessary to meet 10 CFR 50.49. A qualified life is determined for equipment within the scope of the program and appropriate actions such as replacement or refurbishment are taken prior to or at the end of the qualified life of the equipment so that the aging limit is not exceeded. The various aging effects addressed by this program are adequately managed so that the intended functions of components within the scope of 10 CFR 50.49 are maintained consistent with the current licensing basis during the period of extended operation.

The Environmental Qualification (EQ) of Electric Components aging management program will also manage the aging of mechanical environmental qualification (MEQ) components. Qualified lives for MEQ components are established based on aging concerns in accordance with the provisions of Criterion 4 of Appendix A to 10 CFR Part 50. As part of the qualification, replacement intervals were identified as required either on the basis of aging performed during an IEEE 323-1974 qualification test program or on the basis of published material aging data. The program establishes, demonstrates, and documents the level of qualification, qualified configurations, maintenance, surveillance, and replacements necessary to meet UFSAR Section 3.11. The various aging effects on the MEQ components included under Environmental Qualification requirements are adequately managed so that the intended functions of the MEQ components are maintained consistent with the current licensing basis during the period of extended operation.

The Environmental Qualification (EQ) of Electric Components aging management program will be enhanced:

1. To expand the scope of the program to include mechanical environmental qualification (MEQ) components.

This enhancement will be implemented prior to the period of extended operation.

A.4.0 Time-Limited Aging Analyses

As part of the application for a renewed license, 10 CFR 54.21(c) requires that an evaluation of Time-Limited Aging Analyses (TLAAs) for the period of extended operation be provided. The following TLAAs, as defined in 10 CFR 54.3, have been identified and evaluated to meet this requirement.

A.4.1 Identification of Time-Limited Aging Analyses

10 CFR 54.21(c)(2) requires that the application for a renewed license include a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based upon TLAAs as defined in 10 CFR 54.3. It also requires an evaluation that justifies the continuation of these exemptions for the period of extended operation. Six exemptions were identified that are based upon a TLAA. All six were associated with the development of the Pressure-Temperature (P-T) limits that are applicable for 32 EFPY. It is anticipated that these exemptions will not be required to be in effect during PEO since Byron, Units 1 and 2 and Braidwood, Units 1 and 2 are expected to exceed 32 EFPY prior to the period of extended operation (PEO) necessitating replacement of the P-T limit curves in accordance with 10 CFR 50, Appendix G. Continuation of these exemptions into the PEO, if necessary, is acceptable because the use of the exemptions as a basis for the 32 EFPY P-T limits was approved by the NRC without a limitation with respect to plant operation beyond the original license term. The exemptions and their acceptability are not tied to or limited by the original license term.

The following TLAAs have been identified and evaluated to meet 10 CFR 54.21(c) requirements.

A.4.2 Reactor Vessel Neutron Embrittlement Analysis

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, P-T limits, and material surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50 Appendices G and H. The BBS Reactor Vessel Surveillance program is described in Section A.2.1.19.

The ferritic materials of the reactor vessel are subject to reduction in fracture toughness due to high-energy neutron exposure over time. Neutron embrittlement analyses are used to account for the reduction in fracture toughness associated with the cumulative neutron fluence during the life of the plant. The reactor vessel embrittlement calculations for BBS that evaluated reactor vessel beltline materials for loss of fracture toughness for 40 years are based upon a predicted fluence of 32 EFPY. These analyses were identified as TLAAs as defined in 10 CFR 54.21(c) and they were evaluated for the increased neutron fluence associated with 60 years of operation as described in the subsections below.

A.4.2.1 Neutron Fluence Projections

The fluence projections used as inputs to the original 40-year neutron embrittlement analyses were developed using the discrete ordinates transport fluence methodology. At the time the original projections were prepared, 32 EFPY was considered to represent the amount of power to be generated over 40 years of plant operation.

Updated fluence projections were developed for 60 years of plant operation, based upon 57 Effective Full Power Years (EFPY) for use as inputs to updated neutron embrittlement analyses for the PEO. They were also used to determine if any additional materials will be exposed to fluence greater than 1.0×10^{17} n/cm^2 (E > 1.0 MeV) through the PEO, which would be in the extended beltline. The 57 EFPY fluence projections were developed using methodologies that follow the guidance of Regulatory Guide 1.190. The 57 EFPY fluence projections have been determined for reactor vessel beltline and extended beltline materials, which include all reactor vessel forgings and welds that are predicted to be exposed to 1.0×10^{17} neutrons/cm2 (n/cm2) or more during 60 years of operation. Therefore, these TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.2 Upper Shelf Energy

Appendix G of 10 CFR 50, Paragraph IV.A.1.a, states that reactor vessel beltline materials must have Charpy upper-shelf energy of no less than 75 ft-lb initially and must maintain Charpy upper-shelf energy (USE) throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

Per Regulatory Guide 1.99, Revision 2, the Charpy USE should be assumed to decrease as a function of fluence according to Figure 2 of the Regulatory Guide when credible surveillance data is not available. If credible surveillance data is available, the decrease in USE may be obtained by plotting the reduced plant surveillance data on Figure 2 of the Regulatory Guide and fitting the data with a line drawn parallel to the existing lines as the upper bound of all of the data.

The USE values for the BBS beltline and extended beltline materials are projected to remain above 50 ft-lb at 57 EFPY of neutron exposure through the period of extended operation. The projections demonstrated that the requirements of 10 CFR 50 Appendix G will continue to be met through the period of extended operation. Therefore, these TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.3 Pressurized Thermal Shock

10 CFR 50.61(b)(1) provides rules for protection against pressurized thermal shock (PTS) events for pressurized water reactors. Licensees are required to perform an updated assessment of the projected values of the PTS reference temperature (RT_{PTS}) whenever there is a significant change in projected values of RT_{PTS} or upon a request for a change in the expiration date for operation of the facility. The current analyses, evaluated for 32 EFPY fluence values predicted for 40 years of operation, were identified as TLAAs requiring evaluation for 60 years.

Each BBS Units 1 and 2 reactor vessel material that has a surface fluence value that exceeds 1.0×10^{17} n/cm^2 (E > 1.0 MeV) at 57 EFPY has been demonstrated to have an RT_{PTS} value less than the applicable screening criterion, which is 270 degrees F for plates, forgings, and axially-oriented welds (longitudinal welds), and 300 degrees F for circumferentially-oriented welds. The RT_{PTS} analyses have been satisfactorily projected for 60 years of operation. Therefore, these TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.4 Adjusted Reference Temperature

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the beltline P-T limit curves to account for irradiation effects. Regulatory Guide 1.99, Revision 2, provides the methodology for determining the ART of the limiting material. The initial nil-ductility reference temperature, RT_{NDT}, is the temperature at which a non-irradiated metal (ferritic steel) changes in fracture characteristics from ductile to brittle behavior. RT_{NDT} is evaluated according to the procedures in the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Paragraph NB-2331. Neutron embrittlement increases the RT_{NDT} beyond its initial value.

10 CFR 50, Appendix G, defines the fracture toughness requirements for the life of the vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lb index temperatures from the average Charpy curves measured before and after irradiation. This increase (ΔRT_{NDT}) means that higher temperatures are required for the material to continue to act in a ductile manner. The ART is defined as: Initial RT_{NDT} + (ΔRT_{NDT}) + Margin. Since the ΔRT_{NDT} value is a function of 32 EFPY fluence, associated with the 40-year licensed operating period, these ART calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 60 years.

The limiting 1/4T and 3/4T ART values will continue to be provided with the PTLR report to maintain the P-T Limits in accordance with Technical Specification requirements during the period of extended operation as presented in LRA Section 4.2.5, "Pressure-Temperature Limits." Therefore, these TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.2.5 Pressure-Temperature Limits

Appendix G of 10 CFR 50 requires that the reactor vessel be maintained within established pressure-temperature (P-T) limits. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor vessel is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated reactor vessel fluence.

The current P-T limits are based upon 32 EFPY fluence projections that were considered to represent the amount of power to be generated over 40 years of plant operation, assuming a 40-year average capacity factor of 80 percent. The current P-T limits are located in the unit-specific pressure-temperature limit reports (PTLRs). Since they were originally based upon a 40-year assumption regarding capacity factor, the P-T limits satisfy the criteria of 10 CFR 54.3(a) and have been identified as TLAAs.

In accordance with NUREG-1800, Revision 2, Section 4.2.2.1.3, P-T Limits for the period of extended operation need not be submitted as part of the LRA since P-T limits need to be updated through the Administrative Section of the Technical Specifications and the plant's PTLR process. The PTLR revision necessary to extend the P-T limits into the period of extended operation will consider all ferritic materials of pressure-retaining components of the reactor coolant pressure boundary, including the impact of structural discontinuities, and address the impact of neutron fluence accumulation in accordance with the requirements of 10 CFR 50, Appendix G.

The P-T limit curves will be maintained during the period of extended operation using the Administration Section of Technical Specifications to amend the P-T limits through the PTLR process. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.2.6 Low Temperature Overpressure Protection (LTOP) Analyses

Low temperature overpressure protection (LTOP) system at Byron and Braidwood is required by Technical Specification Limited Condition for Operation 3.4.12. Two pressurizer power-operated relief valves (PORV) are used to provide the automatic relief capability during the design basis mass input (MI) and the design basis heat input (HI) transients to automatically prevent the reactor coolant system pressure from exceeding the pressure-temperature limit curves based on 10 CFR 50, Appendix G. The residual heat removal (RHR) suction relief valves may also be used to provide low-temperature overpressure protection (two RHR suction relief valves or one PORV and one RHR suction relief valve). The design basis MI and HI transients are defined in the Updated Final Safety Analysis Report and Technical Specifications Bases.

Since LTOP system setpoints are based on the P-T limits calculation, which is a TLAA, the calculation of the LTOP setpoints and the supporting safety analyses have been identified as TLAAs.

The LTOP system setpoints are established in the PTLRs and managed consistent with the P-T limits, which will be managed through the period of extended operation as described in Section A.4.2.5, Pressure-Temperature (P-T) Limits. P-T Limits for the period of extended operation are not required to be submitted as part of the LRA since P-T limits are updated through the Administrative Section of the Technical Specifications and the plant's Pressure-Temperature Limit Report (PTLR) process. The plant Technical Specifications (5.6.6) will ensure that updated P-T limits based upon updated Adjusted Reference Temperature (ART) values will be submitted to the NRC and approved prior to exceeding the current terms of applicability. Therefore, the LTOP system setpoints will be managed through the period of extended operation. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3 Metal Fatigue

Metal fatigue was considered explicitly in the design process for pressure boundary components designed in accordance with ASME Section III, Class 1 requirements. Metal fatigue was evaluated implicitly for components designed in accordance with ASME Section III, Class 2 and 3, and ANSI B31.1 requirements. In addition, certain other codes such as ASME Section VIII Division 2, may require a fatigue analysis or assume a stated number of full-range thermal and displacement cycles. Each of these fatigue analyses and evaluations are considered to be Time-Limited Aging Analyses (TLAAs) requiring evaluation for the period of extended operation in accordance with 10 CFR 54.21(c) and are listed below.

A.4.3.1 Transient Inputs to Fatigue Analyses

ASME Section III, Class 1 fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients described in the design specifications. The intent of the design basis transient definitions is to bound a wide range of possible events with varying ranges of severity in temperature, pressure, and flow.

Each BBS component designed in accordance with ASME Section III, Class 1 requiring a fatigue analysis was analyzed and shown to have a CUF less than the allowable design limit of 1.0. Some components were exempted from a fatigue analysis based on the code exemption criteria. Since the fatigue analyses and exemptions from fatigue analysis are based upon a number of cycles postulated to bound 40 years of service, projection of the transients cycles through the period of extended operation is required as an input to demonstrate that the analyses and exemptions remain valid.

Some ASME Section III, Class 2 heat exchangers were analyzed and shown to have a CUF less than the allowable design limit of 1.0. Since the fatigue analyses are based upon a number of cycles postulated to bound 40 years of service, projection of the transients cycles through the period of extended operation is required as an input to demonstrate that the analyses remain valid.

Byron Station, Units 1 and 2, have approximately 33 and 35 years of operation remaining for a 60-year life, and Braidwood Station, Units 1 and 2, have approximately 36 and 37 years of operation for a 60-year life as of the year 2012. Using remaining years of operation, baseline cycle counts, and projection rates, the 60-year projected cycles for each of the transients were determined.

The transients have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21 (c)(1)(ii). The overall conclusion of these evaluations is the existing design transients bound transients projected for 60 years of plant operation. The following fatigue TLAAs have been dispositioned using either the design transients or the projected transients for the period of extended operation.

A.4.3.2 ASME Section III, Class 1, Class 2, and Class 3 Fatigue Analyses

The BBS reactor pressure vessels (RPVs) and reactor coolant pressure boundary (RCPB) piping and components were designed in accordance with the ASME Code Section III, Class 1 requirements. Fatigue analyses were prepared for these components to determine the effects of cyclic loadings resulting from changes in system temperature, pressure, and seismic loading cycles. These ASME Section III, Class 1 fatigue analyses are based upon explicit number and amplitudes of thermal and pressure transients projected during the 40-year design life of the plant. The fatigue analyses were required to demonstrate that the Cumulative Usage Factor (CUF) will not exceed the design limit of 1.0 when the equipment is exposed to all of the postulated transients.

The calculation of fatigue usage factors is part of the current licensing basis and are used to support safety determinations and since the number of occurrences of each transient type was based upon 40-year assumptions, these Class 1 fatigue analyses have been identified as time-limited aging analyses.

Some ASME Section III, Class 2 heat exchangers have fatigue analyses. The fatigue analyses were performed in a manner similar to that used for Class 1 components. The fatigue analyses were required to demonstrate that the cumulative usage factor (CUF) will not exceed the design allowable limit of 1.0 when the equipment is exposed to all of the postulated transients. Since the calculation of fatigue usage factors is part of the current licensing basis and the number of occurrences of each transient type was based upon 40-year assumptions, the fatigue analyses performed for Class 2 heat exchangers have been identified as TLAAs requiring evaluation for the period of extended operation.

The 40-year design transient cycle numbers and severity remain bounding for 60 years of plant operation. Therefore, the fatigue analyses for BBS Class 1 vessels, piping, and components and BBS Class 2 heat exchangers remain valid for the period of extended operation.

The design analysis of some BBS ASME Section III, Class 1 components also used the fatigue exemption provisions of ASME Section III, Subparagraph NB-3222.4(d)(1) through (6). The exemption determination is also based on the 40-year design transients described in the design specifications. A review of the provisions of ASME Section III, Subparagraph NB-3222.4(d)(1) through (6) shows that the allowance for an exemption is based upon the number of occurrences of design transient events and the severity of the occurrences. Since these fatigue exemptions are based upon the 40-year design transients, they have also been identified as TLAAs that require evaluation for the period of extended operation.

Some ASME Section III, Class 2 and 3 components at BBS were designed to ASME Section III, Paragraph NC-3219 requirements and were shown to meet the criteria for a fatigue exemption per ASME Section III, Subparagraphs NC-3219.2 and NC-3219.3. The approach taken for the fatigue exemption is similar to that taken in ASME Section III, Subparagraphs NB-3222.4(d)(1) through (6) for a fatigue exemption on Class 1 components and is based upon the number of occurrences of design transient events and the severity of the occurrences.

To ensure the transient cycles used in analysis remain bounding, the Fatigue Monitoring (A.3.1.1) program will be used to monitor transient cycles. This ensures the numbers of transients analyzed in the ASME Section III, Class 1 fatigue analyses, the ASME Section III, Class 2 heat exchangers fatigue analyses, and the ASME Section III, Class 1, Class 2, and Class 3 fatigue exemptions will not be exceeded through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.3 ASME Section III, Class 2 and 3 and ANSI B31.1 Allowable Stress Analyses

Piping and components designed in accordance with ASME Section III, Class 2 and 3, and ANSI B31.1 design rules are not required to have an explicit analysis of cumulative fatigue usage, but cyclic loading is considered in a simplified manner in the design process. These codes first require prediction of the overall number of thermal and pressure cycles expected during the 40-year lifetime of these components. Then a stress range reduction factor is determined for that number of cycles using the applicable design code. If the total number of cycles is 7,000 or less, the stress range reduction factor of 1.0 is applied that would not reduce the allowable stress values. For high numbers of cycles, a stress range reduction factor of less than 1.0 is applied that limits the allowable stresses applied to the piping, which reduces the likelihood of failure due to cyclic loading. These are considered to be an implicit fatigue analysis since they are based upon cycles anticipated for the life of the component.

To demonstrate acceptability from a fatigue basis for 60 years of operation for ASME Section III, Class 2 and 3, and ANSI B31.1 components, the transients considered are based on the Class 1 transients in A.4.3.1. The 60-year cycle projections demonstrate that the total number of thermal and pressure cycles will not exceed 7,000 cycles during the period of extended operation. Therefore, fatigue of ASME Section III, Class 2, 3 and ANSI B31.1 piping will remain valid through the period of extended operation.

The Fatigue Monitoring (A.3.1.1) program will be used to ensure that the numbers of cycles analyzed in the ASME Section III, Class 2 and 3, and ANSI B31.1 analyses will not be exceeded during the period of extended operation. The Fatigue Monitoring (A.3.1.1) program will monitor transient cycles and severities and require action prior to exceeding design limits that would invalidate these conclusions in accordance with 10 CFR 54.21(c)(1)(iii).

For the remaining systems that are affected by different thermal and pressure cycles, an operational review was performed that concluded that the total number of cycles projected for 60 years are significantly less 7,000 cycles. This includes the Auxiliary Feedwater, Emergency Diesel Generator, Fire Protection, Heating Water and Heating Steam System, and Service Water Systems. Therefore, since the projected number of transient cycles does not exceed the number of equivalent full temperature cycles assumed in the implicit stress analysis, the stress range reduction factors originally selected for the components in all of these systems remain applicable. Therefore, the TLAAs remain valid for the period of extended operation.

The ASME Section III, Class 2 and 3 and ANSI B31.1 allowable stress calculations for the Auxiliary Feedwater, Emergency Diesel Generator, Fire Protection, Heating Water and Heating Steam, and Service Water System remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

A.4.3.4 Class 1 Component Fatigue Analyses Supporting GSI-190 Closure

NUREG-1800, Revision 2, provides a recommendation for evaluating the effects of the reactor water environment on the fatigue life of ASME Section III Class 1 components that contact reactor coolant to support closure of GSI-190. One method acceptable to the NRC for satisfying this recommendation is to assess the impact of the reactor coolant environment on a sample of critical components. These critical components should include those selected in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The components that are applicable to Byron and Braidwood Units 1 and 2 are the ones listed for a newer vintage Westinghouse plant. BBS considered adding additional component locations if they are considered to be more limiting than those considered in NUREG/CR-6260.

The environmental fatigue analyses prepared for the BBS, Units 1 and 2 limiting components, equivalent to the locations evaluated in NUREG/CR-6260 for newer vintage Westinghouse plants, demonstrate that cumulative environmental fatigue usage values do not exceed the ASME allowable cumulative fatigue usage value of 1.0. Since the analyses are based on design cycles and 60-year cycle projections, monitoring of usage through the period of extended operation is required to ensure these conclusions remain valid. Where reduced numbers of cycles were used in the environmental fatigue analyses, they will be considered the new CLB cycle limits in the Fatigue Monitoring Program during the period of extended operation. The reduced numbers of cycles are equal to or greater than the 60-year projected cycles.

A review of the screening CUF_{en} for the equipment and piping locations identifies the Pressurizer Spray Nozzle as the most limiting plant specific component location based on the value of the screening CUF_{en}. Consistent with the methods utilized for the NUREG/CR-6260 locations, the Pressurizer Spray Nozzle was successfully evaluated for EAF to show the CUF_{en} to be less than the allowable of 1.0. Additional locations, from the list of limiting locations determined to be potentially limiting, will be evaluated prior to the period of extended operation.

In accordance with 10 CFR 54.21(c)(1)(iii), the Fatigue Monitoring (A.3.1.1) program will be used to ensure that the numbers of cycles used for the environmental fatigue analyses will not be exceeded during the period of extended operation. Additional locations determined to be potentially limiting based on transient section differences will be evaluated. The Fatigue Monitoring (A.3.1.1) program will monitor transient cycles and severities and require action prior to exceeding environmental fatigue usage limits. The program will also ensure additional component locations which may be more limiting than the NUREG/CR-6260 component locations will be evaluated prior to the period of extended operation.

A.4.3.5 Reactor Vessel Internals Fatigue Analyses

BBS reactor vessel internals were designed and procured prior to the issuance of ASME Section III, Subsection NG. The intent of the code is applied with load combinations and allowable stresses, consistent with the requirements of ASME Section III, Subsection NG. The reactor vessel internals were designed to withstand stress originating from the same operating conditions as the reactor vessel. Using the reactor vessel internals stress reports, cumulative usage factors (CUF) less than one were determined for the maximum alternating stresses using the design transient cycles from each transient and the design ASME Code fatigue curve.

The analyses performed for the reactor vessel internals components are based on a subset of the RCS design transients used in the fatigue analyses for the reactor vessel. As stated in subsection A.4.3.1, the transient cycle projections demonstrated that the transient cycle limits applicable to the reactor vessel internals will not be exceeded for 60 years of operation. Therefore, the analyses will remain valid through the period of extended operation and the cumulative usage factors will remain within the allowable limit of 1.0. The Fatigue Monitoring (A.3.1.1) program will monitor transient cycles and severities and require action prior to exceeding design limits that would invalidate these conclusions. Therefore, the analyses will be managed through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.6 High-Energy Line Break (HELB) Analyses Based Upon Fatigue

Locations of postulated high-energy line breaks (HELB) are based upon two limiting stress criteria and a cumulative usage factor criterion. Meeting any one of the criteria results in a break being postulated. The postulations of break locations based on the fatigue criterion at BBS have been identified as TLAAs.

Transient cycle projections were performed that determined the 40-year transient cycle limits will not be exceeded in 60 years. The fatigue analyses were demonstrated to remain valid for the period of extended operation. The Fatigue Monitoring (A.3.1.1) program will monitor transient cycles used as inputs for the determination of postulated break locations, and ensure that the number of analyzed cycles will not be exceeded. If a limit is approached, corrective action will be required prior to exceeding design limits in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.7 NRC Bulletin 88-11 Revised Fatigue Analysis of the Pressurizer Surge Line for Thermal Cycling and Stratification

NRC Bulletin 88-11, issued in December 1988, requested utilities to establish and implement a program to confirm the integrity of the pressurizer surge line. The program required both visual inspection of the surge line and demonstration that the design requirements of the surge line are satisfied, including the consideration of stratification effects. The demonstration was an ASME Section III fatigue analysis to account for thermal stratification. The analysis uses time-limited assumptions such as thermal and pressure transients, operating cycles, and the licensed life of the plant. Therefore, the analyses required by NRC Bulletin 88-11 have been identified as TLAAs.

The original analyses performed to demonstrate compliance with design requirements considered ASME Code requirements and utilized the design set of NSSS transients. Pressurizer surge line stratification sub-transients were developed based on plant operating procedures, surge line monitoring data from similar units, and historical records for each BBS unit. The ASME Code stress limits and cumulative usage factor requirements were shown to be acceptable for the current license of BBS. The Fatigue Monitoring (A.3.1.1) program will monitor transient cycles and severities which are the inputs to these analyses and require action prior to exceeding design limits that would invalidate these conclusions in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.8 ASME Section III, Subsection NF Class 1 Component Supports Allowable Stress Analyses

BBS Class 1 component supports, which includes supports for the reactor vessel, steam generator, reactor coolant pump, and pressurizer, are designed in accordance with ASME Section III, Subsection NF, and are inherently designed for a minimum of 20,000 stress cycles. These are considered to be implicit fatigue analyses since they are based upon cycles anticipated for the life of the component. Westinghouse report WCAP-14422, Revision 2-A, documents a technical evaluation of cumulative fatigue for the period of extended operation, on ASME Class 1 component supports in Westinghouse nuclear plant, including Byron and Braidwood. The report concludes that the number of actual loading transients that will affect ASME III Class 1 component supports is projected to be significantly lower than 20,000 loading cycles through 60 years of operation. The NRC documented its review of WCAP-14422, Revision 2-A, in an SER contained in a November 17, 2000 letter. With respect to fatigue, the staff agreed with this assessment in WCAP-14422, provided that each license renewal applicant justifies the use of installed materials not listed in Table 2-4 of the WCAP.

This requirement is the result of a concern that the Table 2-4 of the WCAP only contains higher strength materials with a presumed limit of 20,000 loading cycles while the design of some Class 1 supports at older Westinghouse plants may have used the 1963 AISC manual, which specifies a limit of 10,000 loading cycles. Even though BBS Class 1 component supports were designed to ASME Section III, Subsection NF 1974 Edition through the 1975 Summer Addenda requirements and not the AISC 1963 Edition, design documents were reviewed and the majority of installed Class 1 component support materials were found in Table 2-4 of the WCAP. Several materials were identified that were not documented in the table. The evaluation of these different materials showed that their yield strength and fatigue resistance properties are consistent with the materials in Table 2-4 of the WCAP or that the materials are used as shim materials, which are not subject to fatigue since shim materials do not experience cyclical tensile stresses.

The Fatigue Monitoring (A.3.1.1) program will monitor transient cycles and require action prior to exceeding design limits that would invalidate these conclusions. Therefore, this TLAA will be managed in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.9 Fatigue Design of Spent Fuel Pool Liner and Spent Fuel Storage Racks for Seismic Events

The spent fuel storage racks, which were replaced in 2000 and 2001, are designed in accordance with ASME Section III, Division 1, Subsection NF, and were analyzed for fatigue due to seismic events using methods similar to those for ASME Section III, Division 1, Subsection NB. The analyses include a fatigue evaluation of the replacement spent fuel storage racks and for the spent fuel pool liner for the cyclic loads imposed by twenty (20) OBE events plus one (1) SSE event. The analyses calculated a cumulative usage factor (CUF) of less than 1.0 for the spent fuel storage racks and the spent fuel pool liner for the loads imposed by the new racks. The analyses calculated a CUF of less than 1.0 for the spent fuel pool liner. Therefore, these analyses were identified as TLAAs that require evaluation for the period of extended operation.

OBE and SSE events are monitored by the Fatigue Monitoring (A.3.1.1) program. No OBE or SSE events have occurred to date. The Fatigue Monitoring (A.3.1.1) program will continue to be used to manage fatigue of these components through the period of extended operation by monitoring OBE and SSE events. The Fatigue Monitoring (A.3.1.1) program will manage fatigue of these components through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.10 Pressurizer Heater Sleeve Structural Assessment

During the Braidwood Unit 1 refueling outage in May 2006, a leak was discovered in Reactor Coolant Pressurizer heating element penetration sleeve number 52. The sleeve was repaired in accordance with ASME Section III, Subsection NB. The design analysis for the repair evaluated fatigue in accordance with ASME Section III, Subparagraph NB-3222.4. The fatigue evaluation assumed 200 RCS heatup and cooldown transients and has been identified as a TLAA requiring evaluation for the period of extended operation. The 60-year projections of the design transients in Section A.4.3.1 for heatups and cooldowns are less than those used in this analysis. The Fatigue Monitoring (A.3.1.1) program will monitor the transient cycles and require action prior to exceeding the design limits in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.4 Environmental Qualification (EQ) of Electric Components

Thermal, radiation, and cyclical aging analyses of plant electrical and instrumentation components, developed to meet 10 CFR 50.49 requirements, have been identified as time-limited aging analyses (TLAAs) for BBS. The NRC has established nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49 and 10 CFR 50, Appendix A, Criterion 4. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of inservice aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a loss-of-coolant accident (LOCA), high energy line break (HELB), or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification. Aging evaluations for electrical components in the BBS EQ Program that specify a qualification of at least 40 years have been identified as TLAAs for license renewal because the criteria contained in 10 CFR 54.3 are met.

The Environmental Qualification (EQ) of Electric Components (A.3.1.3) program will manage the effects of aging effects for the components associated with the environmental qualification TLAA. This program implements the requirements of 10 CFR 50.49 (as further defined and clarified by NUREG-0588, and RG 1.89, Rev. 1). Component aging evaluations are reanalyzed on a routine basis to extend the qualifications of components as part of the BBS EQ Program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). The Environmental Qualification (EQ) of Electric Components (A.3.1.3) program methodology is further described in Section A.3.1.3.

Under the BBS EQ Program, the reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component must be refurbished, replaced, or re-qualified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner such that sufficient time is available to refurbish, replace, or re-qualify the component if the reanalysis is unsuccessful.

The effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The BBS Environmental Qualification (EQ) of Electric Components (A.3.1.3) program has been demonstrated to be capable of programmatically managing the qualified lives of the electrical and instrumentation components falling within the scope of the program for license renewal in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.5 Concrete Containment Tendon Prestress Analyses

The Byron and Braidwood Stations Containment Structures are a prestressed concrete shell made up of a cylinder with a shallow dome roof and flat foundation slab. The cylindrical and dome portions of the containment structures are prestressed by a post-tensioning system. The prestressing forces decrease with time due to relaxation of the steel tendons and creep and shrinkage of the concrete.

The original design of the Containment Structures considered an estimate of the loss of prestressing forces over time to ensure that prestressing forces remained above the minimum required values at the end of the 40 year period. Examinations performed as part of the Concrete Containment Tendon Prestress (A.3.1.2) aging management program, in accordance with ASME Section XI, Subsection IWL requirements, include the measurement of the prestressing force values from multiple tendons within each tendon group (vertical, hoop, and dome) during periodic examinations. These measurements are compared to minimum required values and predicted lower limit force values to verify that the Containment Structure is performing its intended function, as well as to compare the actual loss of prestress rate to the predicted rate. Trend lines of the individual tendon prestressing force values for each tendon group are developed to predict future tendon prestressing force values to ensure the Containment Structure will continue to perform its intended function.

Trend lines calculated based on the most recent tendon surveillances for all three tendons groups at Byron and Braidwood Stations, Units 1 and 2, have been extended from 40 years to 60 years. In all cases, the trend lines indicate the prestressing forces will remain above the minimum required values through the end of the period of extended operation. The continued implementation of the existing Concrete Containment Tendon Prestress (A.3.1.2) aging management program will provide reasonable assurance that the loss of containment tendon prestress will be adequately managed so that the intended functions are maintained during the period of extended operation. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.6 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analyses

The Byron and Braidwood prestressed concrete Containment Structures are designed to contain the radioactive material released that would be in the unlikely event of design basis accidents. Each Containment Structure includes a welded carbon steel plate liner attached to the entire inside surface. The liner provides a leak-tight membrane. The prestressed concrete Containment Structure and the portion of the carbon steel liner that is, backed by concrete, conform to the ASME Section III, Division 2. The Containment Structure design also includes components that are not backed by concrete, including emergency personnel airlocks, equipment access hatches and integral personnel airlocks, piping and electrical penetrations, and bellows. These features are defined as Class MC components, which are designed in accordance with ASME Section III, Division 1 requirements to withstand design basis accident pressures corresponding to design basis accidents.

A.4.6.1 Containment Liner Plates Fatigue

Each Containment Structure includes a welded carbon steel plate liner attached to the entire inside surface that provides a leak-tight membrane. The original design required a fatigue evaluation in accordance with ASME Section III, Division 1, Subsection NE, based upon design inputs including RCS heatup and cooldown transients and seismic transients. The evaluation determined that the fatigue exemption criteria of ASME Section III, Subparagraph NE-3222.4(d) were met. A re-evaluation confirmed that these exemption criteria remain satisfied through the period of extended operation, since the original design transients bound the 60-year projections for these transients through the period of extended operation. Therefore, the fatigue exemption remains valid through the period of extended operation. The effects of aging on the intended function(s) of the liner will be adequately managed for the period of extended operation by the Fatigue Monitoring (A.3.1.1) program, which monitors transient cycles to ensure the transient limits are not exceeded during the period of extended operation, validating the assumptions used in these evaluations. Therefore, this TLAA will be managed in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.6.2 Containment Airlocks and Hatches Fatigue

The Byron and Braidwood emergency personnel airlock, personnel airlock with equipment hatch, and all penetrations and nozzles associated with personnel airlocks are designed as Class MC components in accordance with the 1971 Edition of ASME Section III, Subsection NE, through the Summer 1973 Addenda. The original design analysis performed a fatigue exemption determination in accordance with ASME Section III, Subparagraph NE-3222.4(d), with design inputs including RCS heatup and cooldown transients and seismic transients. A re-evaluation confirmed that the original inputs remain valid. The temperature differences have not changed because the design transients have not been redefined. The 60-year transient projections show that the transient limits will not be exceeded during the period of extended operation. Therefore, the numbers of temperature and pressure cycles considered in determining the components were exempt from fatigue analysis will not be exceeded. The effects of aging on the intended function(s) of the Class MC components will be adequately managed for the period of extended operation by the Fatigue Monitoring (A.3.1.1) program, which monitors transient cycles to ensure the transient design limits will not be exceeded during the period of extended operation, validating the assumptions used in this analysis. Therefore, this TLAA will be managed in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.6.3 Containment Electrical Penetrations Fatigue

The Byron and Braidwood prestressed concrete Containment Structures include electrical penetrations designed in accordance with ASME Section III, Division 1, Subsection NE, 1977 Edition through Summer 1978 Addenda requirements. The original design analysis for the Byron and Braidwood Containment Structure electrical penetrations determined that the design inputs met the exemption criteria of ASME Section III, Subparagraph NE-3222.4(d) and that no fatigue analysis was required. A re-evaluation confirmed that the exemption criteria remain valid through the period of extended operation since the original design transients bound the 60-year projections for these transients through the period of extended operation. The effects of aging on the intended function(s) of the Containment Structure electrical penetrations will be adequately managed for the period of extended operation by the Fatigue Monitoring (A.3.1.1) program, which monitors transient cycles to ensure they do not exceed their design limits, validating the assumptions used in these evaluations. Therefore, this TLAA will be managed in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.6.4 Containment Piping Penetrations Fatigue

The Byron and Braidwood Containment Structure piping penetrations are designed to the requirements of the 1971 Edition of ASME Section III, Subsection NE, through the Summer 1973 Addenda. The Containment Structure instrument and process piping penetrations were analyzed in accordance with design specifications that required fatigue evaluation of in accordance with subparagraph NB-3222.4(e) or NE-3222.4(e) of ASME Section III. The resulting piping penetration stress analyses contain fatigue evaluations that have been identified as TLAAs.

The original design specifications for the containment piping penetrations define the design transients applicable for the fatigue analyses. The same transients are addressed in Section A.4.3.1, along with the 60-year projections. The numbers of some load/unload cycles were originally underestimated in the Main Steam and Feedwater containment piping penetration analyses and were not consistent with the governing Westinghouse transient design specification. Review of these analyses show that there is sufficient margin to accommodate the greater number of transients in the Westinghouse specification. For the remaining penetration analyses, the 60-year projected numbers of cycles are less than the numbers analyzed, so these analyses will remain valid through the period of extended operation. The effects of aging on the intended function(s) of the containment penetrations will be adequately managed for the period of extended operation by the Fatigue Monitoring (A.3.1.1) program, which monitors transient cycles to ensure they do not exceed their design limits. The program also ensures that, if a transient limit is approached corrective action is taken to reanalyze components prior to exceeding a transient limit. Therefore, this TLAA will be managed in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.6.5 Fuel Transfer Tube Bellows Fatigue

The fuel transfer tubes connect the refueling cavity (inside the Containment Structure) to the fuel transfer canal (inside the Fuel Handling Building). The fuel transfer tubes pass through the Containment Structure wall and through the exterior wall of the Fuel Handling Building. Guard pipe assemblies, which also function as penetration sleeves, are utilized for the fuel transfer tubes. There are three expansion bellows in each penetration sleeve, designed to the requirements of the 1974 Edition of ASME Section III, Subsection NE through the Summer 1974 Addenda. These design inputs for these bellows include 1 SSE and 1 LOCA transient that envelope all postulated design basis conditions. The original design transients bound the corresponding 60-year projections for these transients. Therefore, the bellows fatigue analyses remain valid through the period of extended operation. The effects of aging on the intended function(s) of the fuel transfer tube bellows will be adequately managed for the period of extended operation by the

Fatigue Monitoring (A.3.1.1) program, which monitors transient cycles to ensure the transient limits are not exceeded through the period of extended operation. Therefore, this TLAA will be managed in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.6.6 Recirculation Sump Guard Piping Bellows Fatigue

The guard pipe for the containment recirculation sump effluent piping extends from the recirculation sump, inside the Containment Structure, to the sump suction valve chamber inside the Auxiliary Building. The guard pipe is comprised of a 28-inch diameter sleeve that penetrates through the Containment Structure and Auxiliary Building walls and three (3) sets of expansion joints (bellows). One set of bellows seals is in the Containment Structure between the containment sump piping and the guard pipe located inside the Containment Structure. The other two sets of bellows are in the Auxiliary Building on either side of the recirculation sump suction valve chamber. One of these bellows seals between the end of the guard pipe where it extends outside the containment boundary, and the recirculation sump suction valve chamber, inside the Auxiliary Building. A third bellows is located between the recirculation sump suction valve protection chamber and the containment recirculation sump effluent piping. These bellows were analyzed in accordance with ASME Section III, subsection NE for fatigue, based upon design inputs including RCS heatup and cooldown transients, OBE transients, and other upset, emergency, and faulted conditions that would fill the containment recirculation sump. The original design transients bound the 60-year projections for these transients through the period of extended operation. The effects of aging on the intended function(s) of the recirculation sump guard pipe bellows will be adequately managed for the period of extended operation by the Fatigue Monitoring (A.3.1.1) program, which monitors transient cycles to ensure they do not exceed their design limits, validating the assumptions used in this analysis. Therefore, this TLAA will be managed in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.7 Other Plant-Specific Time-Limited Aging Analyses

A.4.7.1 Leak-Before-Break

Appendix A, Criterion 4, of 10 CFR 50 allows for the use of leak-before-break (LBB) methodology for excluding the dynamic effects of postulated ruptures in reactor coolant system piping. The fundamental premise of the LBB methodology is that the materials used in nuclear power plant piping are sufficiently tough that even a large through-wall crack would remain stable and would not result in a double-ended pipe rupture. Application of the LBB methodology is limited to those high-energy fluid systems not considered to be overly susceptible to failure from such mechanisms as corrosion, water hammer, fatigue, thermal aging or indirectly from such causes as missile damage or the failure of nearby components. The analyses associated with LBB have been identified as TLAAs. Original LBB analyses performed for Byron and Braidwood Stations, Units 1 and 2,demonstrated that postulated breaks can be eliminated from the structural design basis in the reactor coolant primary loop piping, safety injection accumulator piping and cold leg nozzles, and reactor coolant bypass piping. The reactor coolant primary loop piping includes cast austenitic stainless steel (CASS) elbows, and the safety injection accumulator piping cold leg nozzles are also fabricated from CASS material. The LBB analyses for these systems were updated for license renewal to consider the effects of additional thermal aging on the fracture toughness of the CASS materials through the period of extended operation. The fracture toughness properties used were based on the fully-aged condition (that has the lowest possible fracture toughness), which is applicable for the period of extended operation. The updated LBB analyses demonstrate that the dynamic effects of the pipe rupture resulting from postulated breaks in the reactor coolant primary loop piping and safety injection accumulator piping cold leg nozzles need not be considered in the structural design basis for BBS Units 1 and 2 for the license renewal period. The analyses have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.7.2 Crane Load Cycle Limits

The below cranes within the scope of license renewal were reviewed and found to be designed in accordance with the Crane Manufacturers Association of America (CMAA) Specification 70. Cranes designed in accordance with CMAA-70 include considerations for frequency of operation and expected size of lifts, relative to their maximum load capacity. Based upon these considerations, cranes are designated a given service classification with an expected number of lifts over their life, which also correlates to a number of cycles on structural members. These assumptions on the number of planned cycles over the 40-year life of the crane provide the basis for the TLAA evaluation.

Containment Polar Crane

The containment polar crane was designed in accordance with CMAA-70 for Class A service, which includes consideration of 100,000 cycles over the life of the crane. The number of anticipated lifts for the containment polar crane is estimated to be 1,900 through the period of extended operation, which is less than the 100,000 cycles specified for Class A cranes in CMAA-70.

Fuel Handling Building Crane

The fuel handling building crane was designed in accordance with CMAA-70 for Class A service, which includes consideration of 100,000 cycles over the life of the crane. The number of anticipated lifts for the fuel handling building crane is estimated to be 7,200 through the period of extended operation, which is less than the 100,000 cycles specified for Class A cranes in CMAA-70.

Manipulator Crane

The manipulator crane was designed in accordance with CMAA-70 for Class C service, which includes consideration of 500,000 cycles over the life of the crane. The number of anticipated lifts for the manipulator crane is estimated to be 16,000 through the period of extended operation, which is less than the design value of 500,000 cycles specified for Class C cranes in CMAA-70.

Spent Fuel Pool Bridge Crane

The spent fuel pool bridge crane was designed in accordance with CMAA-70 for Class A service, which includes consideration of 100,000 cycles over the life of the crane. The number of anticipated lifts for the spent fuel pool bridge crane is estimated to be 76,900 through the period of extended operation, which is less than the 100,000 cycles specified for Class A cranes in CMAA-70.

Turbine Building Crane

The turbine building crane was designed in accordance with CMAA-70 for Class A service, which includes consideration of 100,000 cycles over the life of the crane. The number of anticipated lifts for the turbine building crane is estimated to be less than 5,100 through the period of extended operation, which is less than the 100,000 cycles specified for Class A cranes in CMAA-70.

These analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.7.3 Mechanical Environmental Qualification

Qualified lives for safety-related mechanical components located in harsh environments are established based on aging concerns in accordance with the provisions of Criterion 4 of Appendix A to 10 CFR Part 50. As part of the qualification, replacement intervals were identified as required either on the basis of aging performed during an IEEE 323-1974 qualification test program or on the basis of published material aging data. The results of qualification tests or other published material aging data have been documented in individual mechanical component Environmental Qualification Binders. The design basis conditions during the period of extended operation will remain the same as those in the current license period. Therefore, the design basis event parameters, including the temperature, radiation, and humidity, do not require further evaluation for license renewal. The individual mechanical components Environmental Qualification Binders are revised to address the 60 year component service requirements. This ensures the effects of aging on the intended function(s) of mechanical components included under Environmental Qualification requirements will be adequately addressed for the period of extended operation. Therefore the aging effects on the mechanical components included under Environmental Qualification requirements will be managed for the period of extended operation, and the TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.7.4 Residual Heat Removal Heat Exchangers Tube Side Inlet and Outlet Nozzles Fracture Mechanics Analysis

During ultrasonic (UT) examinations in 1991, indications were found in the residual heat removal heat (RHR) exchanger tube side nozzles of both the Braidwood 2A and 2B RHR heat exchangers. Subsequently, UT examinations were performed of all the residual heat removal (RHR) heat exchanger tube side inlet and outlet nozzles at Byron and Braidwood and any indications exceeding the Subarticle IWB-3500 acceptance standards were dispositioned with the results of the fracture mechanics analysis. To develop the maximum allowable indication size and determine crack growth rates, the analysis uses the startup and shutdowns of the RHR system coincident with the number of plant heatup and cooldowns as inputs. Since the numbers of design transients analyzed are based on the current licensed operation period, the fracture mechanics analysis has been identified as a TLAA that requires evaluation for the period of extended operation.

The analysis considers the numbers of RHR system startups and shutdowns to be coincident with the 200 RCS heatup and cooldown design transients. Since the 60-year projections of heatup and cooldown transients provided in Section A.4.3.1 have been demonstrated to be lower than the transient design limit of 200 cycles, the transient inputs to the analysis also remain bounded by the transient design limits in Section A.4.3.1. The Fatigue Monitoring (A.3.1.1) program will be used to ensure these limits are not exceeded.

The Fatigue Monitoring (A.3.1.1) program will monitor the transient cycles to ensure the transient inputs used in the fracture mechanics analysis will not be exceeded during the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.7.5 Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis

Due to industry operating experience, the possibility of reactor coolant pump overspeed or reactor coolant pump vibration prompted concerns regarding the potential effects of missiles that might result from the failure of the reactor coolant pump motor flywheel including damage to reactor coolant pump seals or other pressure boundary components.

The reactor coolant pump motor flywheel inspection program is specified in Technical Specifications 5.5.7. Compliance with Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity," is set forth in UFSAR Appendix A - Application of NRC Regulatory Guides, including a description of the inservice inspection program for pump motor flywheels.

The bases for the 10-year inspection interval and the 20-year inspection interval for the reactor coolant pump motor flywheels are provided by fatigue crack growth analyses that assume 6000 starts and stops during the 60-year life of the flywheels. The analyses have been identified as TLAAs.

The inspection interval of ten years for two (2) reactor coolant pump motor flywheels (serial numbers 1S88P961 and 4S88P961) is based on the fatigue crack growth analysis contained in WCAP-14535A, Revision 0, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination." The inspection interval of twenty years for the other reactor coolant pump motor flywheels is based on the fatigue crack growth analysis contained in WCAP-15666-A, Revision 1, "Extension of Reactor Coolant Pump Motor Flywheel Examination."

Based on the 60-year projections of reactor coolant pump starts and stops, the maximum number of start-stop cycles projected to occur in 60 years in any BBS Unit is 1,755 cycles. Therefore, since the number of analyzed cycles significantly exceeds the number of projected cycles, the reactor coolant pump flywheel fatigue analyses have been demonstrated to remain valid through the period of extended operation.

Based on the above information, the reactor coolant pump motor flywheel fatigue analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.7.6 Byron Unit 2 Pressurizer Seismic Restraint Lug Flaw Evaluation

In September 2005, an indication exceeding the acceptance standards of ASME Section XI, Subarticle IWB-3500 1989 Edition was found on a Byron Unit 2 pressurizer seismic lug. Investigation concluded that the indication was not service-induced, but rather was due to lack of fusion in the original weld. A flaw growth analysis was performed in accordance with ASME Section XI, Subarticle IWB-3600, 1989 Edition, which concluded that the indication size will remain within acceptable limits for the current remaining licensed operating period. The analysis assumed input transients for the current licensed operating period based on 40-year operation, and has therefore been identified as a TLAA requiring evaluation for the period of extended operation.

The number of design transients assumed in the analysis bound the numbers of transients projected to occur through the period of extended operation. The ASME Section XI flaw growth analysis will be managed by the Fatigue Monitoring (A.3.1.1) program, which will monitor transient cycles and require corrective action prior to exceeding assumed input transients cycles to ensure the transient inputs used in the analysis will not be exceeded during the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.7.7 Braidwood Unit 2 Feedwater Indication Pipe Elbow Fatigue Crack Growth Evaluation

In October 2009, an axial indication was identified on a 16-inch main feedwater line elbow, downstream of the feedwater regulating valves. A flaw growth analysis performed in accordance with ASME Section XI Subarticle IWB-3600, concluded that the crack size will remain within acceptable limits over the 40-year life of the plant. The analysis used design transient inputs assumed for the current licensed operating period, including 240 RCS heatup transients, 200 RCS cooldown transients, 240 reactor trip transients, and 160 reactor trips with RCS cooldown transients. The flaw growth analysis has been identified as a TLAA requiring evaluation for the period of extended operation. The number of design transients assumed in the analysis bound the number of transients projected to occur through the period of extended operation.

The Fatigue Monitoring (A.3.1.1) program will monitor the transient cycles ensure the transient inputs used in the ASME Section XI flaw growth analysis will not be exceeded during the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.7.8 Analyses Supporting Flaw Evaluations of Primary System Components

Fatigue Crack Growth Analyses

BBS Units 1 and 2 have performed pre-emptive flaw evaluations on reactor vessel, pressurizer, primary steam generator sub-components, and primary coolant components (i.e. primary system components) consistent with ASME Section XI, Subarticle IWB-3600. The flaw evaluations were performed consistently with the methodologies in with WCAP-11063, "Handbook on Flaw Evaluations for Byron Unit 1 and 2 Steam Generators and Pressurizers", earlier in plant life, and now with those in WCAP-12046 Revision 1, "Handbook on Flaw Evaluations for the Byron and Braidwood Units 1 and 2 Reactor Vessels". The handbooks for flaw evaluation methodology are based on crack growth rate analyses that used 40-year design transients as inputs to the crack growth rate reference curves, which were used in evaluating each of the components. Since the flaw evaluation handbooks are based on analyses, which have time-limited inputs (e.g. number of transients assumed over 40 years), these analyses supporting flaw evaluations of primary system components have been identified as TLAAs.

The number of design transients used to develop these curves bound the number of transients projected to occur in 60 years, provided in Section A.4.3.1. The Fatigue Monitoring (A.3.1.1) program will be used to ensure that the number of transients used in these curves will not be exceeded during the period of extended operation.

The ASME Section XI crack growth analyses will be managed by the Fatigue Monitoring Program (A.3.1.1), which will monitor transient cycles and require corrective action prior to exceeding numbers of transients cycles used in the evaluations, which support these conclusions in accordance with 10 CFR 54.21(c)(1)(iii).

Fracture Toughness Input to Analyses - Irradiation Embrittlement of Reactor Vessel Beltline and Extended Beltline Components

The analyses also use fracture toughness as an input. Loss of fracture toughness occurs in those portions of the reactor vessel exposed to neutron fluence over the life of the reactor vessel. Therefore, the analyses using fracture toughness as an input, which are based upon 40-year fluence values, have been identified as TLAAs.

Since fracture toughness will be changing as a result of operating into the period of extended operation and new locations will become a part of the extended beltline, any effects on the analyses are evaluated. For the active beltline region, the projected RT_{NDT} for Byron and Braidwood resulting from fluence associated with 57 EFPY in 60 years remains less than 200°F. Therefore, the flaw evaluation per WCAP-12046 remains applicable for the period of extended operation.

For the extended beltline region even considering a worst case Chemistry Factor, the increase in RT_{PTS} is only 2 degrees F, which is negligible. The fluence will only be lower further down the reactor vessel wall, so effects will continue to be negligible.

Just above the beltline region, the calculated K_{Ic} and K_{Ia} (fracture toughness) value is greater than 200 ksi-in$^{1/2}$ based on RT_{PTS} = 90°F and the limiting temperature from the bounding transient. Since the flaw evaluations for the extended beltline regions are determined based on an upper shelf limit of 200 ksi-in$^{1/2}$, the flaw evaluations for the extended beltline region remain valid for the period of extended operation.

The ASME Section XI analyses supporting the flaw evaluations for the reactor vessel remain valid during the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.5.0 License Renewal Commitment List

Note: This table contains commitments related to the renewed Byron and Braidwood operating licenses. Because these commitments are contained within the UFSAR, any potential changes to these commitments require evaluation in accordance with 10 CFR 50.59 as defined per the Exelon commitment management process. In addition, the commitment management process must be followed to ensure that the commitment-tracking database is updated with the latest commitment implementation information. Refer to Passport AR 1367499 for Byron and 1367498 for Braidwood license renewal commitment tracking information.

Explanatory notes within this table provide the basis for station-specific differences as follows:

Note 1 – Enhancement at one Station only; other Station currently performs activity
Note 2 – Design difference
Note 3 – Enhancement due to operating experience

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD is an existing program that will be enhanced to: 1. Conduct a visual inspection of the accessible portions of the ASME Class 2 reactor vessel flange leakage monitoring tube every other refueling outage. 2. Perform non-destructive examination of the five (5) centermost CRDM housing penetrations to determine the thermal sleeve centering tab wear depth on the CRDM housing penetration inner diameter wall. On each unit, these CRDM housings will be examined at least once during the 10-year period prior to the period of extended operation, and on a 10-year frequency during the period of extended operation.	Program to be enhanced no later than six months prior to the period of extended operation. Pre-PEO inspections specified in Enhancement 2 will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	Section A.2.1.1 Exelon letter RS-15-067 02/11/2015
2	Water Chemistry	Existing program is credited.	Ongoing	Section A.2.1.2

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
3	Reactor Head Closure Stud Bolting	Reactor Head Closure Stud Bolting is an existing program that will be enhanced to: 1. Revise the procurement requirements for reactor head closure stud material to assure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.3 Exelon letter RS-13-247 11/05/2013 RAI B.2.1.3-2 Exelon letter RS-13-285 12/19/2013 RAI B.2.1.3-2 updated response
4	Boric Acid Corrosion	Existing program is credited.	Ongoing	Section A.2.1.4
5	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	Existing program is credited.	Ongoing	Section A.2.1.5
6	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) is a new program that manages the aging effects of loss of fracture toughness due to thermal aging embrittlement of ASME Code Class 1 CASS components with service conditions above 250°C (482°F). The program will include a screening methodology to determine component susceptibility to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. For "potentially susceptible" components, thermal aging embrittlement management will be accomplished through either, qualified visual inspections, such as enhanced visual examination, qualified ultrasonic testing methodology, or component-specific flaw tolerance evaluation.	Program to be implemented no later than six months prior to the period of extended operation.	Section A.2.1.6

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
7	PWR Vessel Internals	The PWR Vessel Internals is a new program that manages the aging effects of various forms of cracking, including stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), irradiation assisted stress corrosion cracking (IASCC), or cracking due to fatigue/cyclical loading; loss of material due to wear; loss of fracture toughness due to neutron irradiation embrittlement; changes in dimension due to void swelling and irradiation growth; and loss of preload due to thermal and irradiation-enhanced stress relaxation or creep. Program examination methods include visual examination, enhanced visual examination, volumetric examination, and direct physical measurements.	Program was implemented prior to receipt of the renewed operating licenses.	Section A.2.1.7
8	Flow-Accelerated Corrosion	The Flow-Accelerated Corrosion aging management program is an existing program that will be enhanced to: 1. Revise program procedures to require the documentation of the validation and verification of updated vendor supplied FAC program software which calculates component wear, wear rates, remaining life, and next scheduled inspection. The validation and verification will verify that the updated software performs these calculations consistently with NSAC-202L-R4 guidelines.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.8 Exelon letter RS-14-143 05/15/2014 RAI B.2.1.8-2
9	Bolting Integrity	Bolting Integrity is an existing program that will be enhanced to: 1. Prohibit the use of lubricants containing molybdenum disulfide on pressure retaining bolted joints. 2. Prohibit the use of high strength bolting (actual measured yield strength equal to or greater than 150 ksi) for pressure retaining bolted joints in portions of systems within the scope of the Bolting Integrity program. 3. Perform visual inspection of submerged bolting on fire protection system pumps	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.9

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		(Byron only) Note 1 and well water system deep well pumps (Byron only) Note 2 when submerged portions of the pumps are overhauled or replaced during maintenance activities.		
10	Steam Generators	Steam Generators is an existing program that will be enhanced to: 1. Validate that primary water stress corrosion cracking of the divider plate welds to the primary head and tubesheet cladding is not occurring. BBS commits to perform one (1) of the following three (3) resolution options for Units 1 and 2: Option 1: Inspection Perform a one-time inspection, under the Steam Generators program, of each steam generator to assess the condition of the divider plate welds and the effectiveness of the Water Chemistry (A.2.1.2) program. For the Byron and Braidwood, Unit 1 steam generators which were replaced in 1998, the inspection will be performed between 2018 and either no later than six months prior to the start of the period of extended operation or the end of the last refueling outage prior to the PEO, whichever occurs later, to allow the steam generators to acquire at least twenty years of service. For the Byron and Braidwood, Unit 2 steam generators which currently have at least twenty years of service, the inspection will be performed prior to entering the period of extended operation. The examination technique(s) will be capable of detecting primary water stress corrosion cracking (PWSCC) in the divider plate assemblies and associated welds. or	Program to be enhanced no later than six months prior to the period of extended operation. Schedule for inspection and analysis activities identified in Commitment.	Section A.2.1.10 Exelon Letter RS-14-052 03/04/2014 RAI B.2.1.10-1

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		Option 2: Analysis Perform an analytical evaluation of the steam generator divider plate welds in order to establish a technical basis which concludes that the steam generator reactor coolant pressure boundary is adequately maintained with the presence of steam generator divider plate weld cracking. The analytical evaluation will be submitted to the NRC for review and approval two (2) years prior to entering the associated period of extended operation. or Option 3: Industry/NRC Studies If results of industry and NRC studies and operating experience document that potential failure of the steam generator reactor coolant pressure boundary due to PWSCC of the steam generator divider plate welds is not a credible concern, this commitment will be revised to reflect that conclusion. 2. Validate that primary water stress corrosion cracking of the tube-to-tubesheet welds is not occurring on BBS Unit 1. BBS commit to perform one (1) of the following three (3) resolution options for Unit 1: Option 1: Inspection Perform a one-time inspection, under the Steam Generators (A.2.1.10) program, of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. Since the Byron and Braidwood Unit 1 steam generators were replaced in 1998, the inspection will be performed between 2018 and either no later than six months prior to the start of the period of extended operation or the end		

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		of the last refueling outage prior to the PEO, whichever occurs later, to allow the steam generators to acquire at least twenty years of service. The examination technique(s) will be capable of detecting primary water stress corrosion cracking (PWSCC) in the tube-to-tubesheet welds. If cracking is identified, the condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and a periodic monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators. or <u>Option 2: Analysis – Susceptibility</u> Perform an analytical evaluation of the steam generator tube-to-tubesheet welds to determine that the welds are not susceptible to primary water stress corrosion cracking. The evaluation for determining that the tube-to-tubesheet welds are not susceptible to primary water stress corrosion cracking will be submitted to the NRC for review and approval two (2) years prior to entering the associated period of extended operation. or <u>Option 3: Analysis – Pressure Boundary</u> Perform an analytical evaluation of the steam generator tube-to-tubesheet welds redefining the reactor coolant pressure boundary of the tubes, where the steam generator tube-to-tubesheet welds are not required to perform a reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary will be submitted to		

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		the NRC for review and approval two (2) years prior to entering the associated period of extended operation		
11	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System is an existing program that will be enhanced to: 1. Perform periodic volumetric inspections for loss of material in the non-essential service water system piping at a minimum of two (2) locations on each unit in both the auxiliary building and the turbine building for a total of four (4) periodic inspections per unit every refueling cycle. 2. Require inspections of internal coatings be performed by coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54. 3. Specify that signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the corrective action program. 4. Require physical testing of internal coatings, where physically possible, to ensure that remaining coating is tightly bonded to the base metal when peeling, blistering, or delamination is detected and the coating is not repaired or replaced. The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07). 5. Require that evaluations utilized to return a coated component exhibiting signs of peeling, blistering, or delamination to service without repairing or replacing the coating shall consider the potential impact on the intended function of the system. This evaluation shall include consideration of the potential for degraded performance of downstream components due to flow blockage and loss of material of the coated component.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.11 Exelon letter RS-14-124 05/05/2014 RAI 3.0.3-2a Exelon letter RS-14-175 06/30/2014 RAI 3.0.3-2b

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		6. Require the as-left condition of a coating that exhibited signs of peeling, blistering, or delamination and that is not repaired or replaced is such that the potential for further degradation of the coating is minimized.		
12	Closed Treated Water Systems	Closed Treated Water Systems is an existing program that will be enhanced to: 1. Perform condition monitoring, including periodic visual inspections and non-destructive examinations, to verify the effectiveness of water chemistry control at mitigating aging effects. A representative sample of piping and components will be selected based on likelihood of corrosion, fouling, or cracking and inspected at an interval not to exceed once in 10 years during the period of extended operation. The selection of components to be inspected will focus on locations which are most susceptible to age-related degradation, where practical. 2. Perform periodic sampling, analysis, and trending of water chemistry for the essential service water makeup pump engine glycol-based jacket water system to verify the effectiveness of water chemistry control at mitigating aging effects (Byron only) [Note 2].	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.12
13	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems is an existing program that will be enhanced to: 1. Consistently include inspections of structural components and bolting for loss of material due to corrosion, rails for loss of material due to wear and corrosion, and bolted connections for evidence of loss of preload.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.13

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		2. Ensure periodic inspections are performed on all cranes, hoists, monorails, and rigging beams within the scope of license renewal, including those that are infrequently in use.		
14	Compressed Air Monitoring	Compressed Air Monitoring is an existing program that will be enhanced to: 1. Inspect critical component internal surfaces for signs of loss of material due to corrosion and document deficiencies in the corrective action program.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.14
15	Fire Protection	Fire Protection is an existing program that will be enhanced to: 1. Include visual inspections of the earthen berm enclosing the outdoor fuel oil storage tanks for signs of age-related degradation such as loss of material and loss of form that could affect the intended function of the berm. 2. Provide additional inspection guidance to identify age-related degradation of fire barrier walls, ceilings, and floors or aging effects such as cracking, spalling, and loss of material. 3. Include visual inspection of halon and low-pressure carbon dioxide fire suppression system piping and component external surfaces for signs of corrosion or other age-related degradation.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.15

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
16	Fire Water System	Fire Water System is an existing program that will be enhanced to: 1. Replace sprinkler heads or perform 50-year sprinkler head testing using the guidance of NFPA 25 "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2002 Edition), Section 5.3.1.1.1. This testing will be performed at the 50-year in-service date and every 10 years thereafter. 2. Provide for chemical addition accompanied with system flushing to allow for adequate dispersal of the chemicals throughout the system, to prevent or minimize microbiologically induced corrosion (Byron only) Note 3. 3. Perform main drain testing annually, in accordance with NFPA 25, "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems," Section 13.2.5. 4. Perform air flow testing of deluge systems that are not subject to periodic full flow testing on a three (3) year frequency to verify that internal flow blockage is not occurring (Byron only) Note 1. 5. Perform inspections of Fire Protection System strainers when the system is reset after automatic actuation for signs of internal flow blockage (e.g., buildup of corrosion particles) (Braidwood only) Note 1. 6. Increase the frequency of visual inspections of the internal surface of the foam concentrate tanks to at least once every ten (10) years. At least one (1) inspection will be performed within the ten (10) year period prior to entry into the period of extended operation, with	Program to be enhanced no later than six months prior to the period of extended operation. Pre-PEO activities specified in Enhancements 6 and 8 will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	Section A.2.1.16 Exelon letter RS-14-078 03/13/2014 RAI B.2.1.16-1 RAI B.2.1.16-2 Exelon letter RS-14-169 06/16/2014 RAI B.2.1.16-1a Exelon letter RS-14-175 06/30/2014 RAI 3.0.3-2b Exelon letter RS-14-235 08/29/2014 RAI B.2.1.16-1c

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		subsequent inspections performed every ten (10) years thereafter. 7. Perform radiographic testing or internal visual inspections every five (5) years at the end of one (1) fire main and the end of one (1) sprinkler system branch line in half of the wet pipe sprinkler system within the scope of license renewal. If internal flow blockage that could result in failure of the system to deliver the required flow is identified, then perform an obstruction investigation. 8. Perform augmented testing beyond that specified in NFPA 25 on those portions of the water-based fire protection system that are: (a) normally dry but periodically subjected to flow and (b) cannot be drained or allow water to collect. The augmented testing will include: (1) periodic full flow tests at the design pressure and flow rate or internal visual inspections and (2) volumetric wall-thickness examinations. Inspections and testing will commence five (5) years prior to the period of extended operation and will be conducted on a five (5) year frequency thereafter. 9. Perform a minimum of 30 volumetric examinations of Fire Protection System piping, using radiographic testing or ultrasonic testing, during each three year interval. If volumetric examinations over a 10-year interval do not identify three (3) or more areas exhibiting reduction in wall thickness greater than 50 percent, then this minimum sample size is no longer required (Byron only)[Note 3]. 10. Require inspections of internal coatings be performed by coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54.		

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		11. Specify that signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the corrective action program. 12. Require physical testing of internal coatings, where physically possible, to ensure that remaining coating is tightly bonded to the base metal when peeling, blistering, or delamination is detected and the coating is not repaired or replaced. The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07). 13. Require that evaluations utilized to return a coated component exhibiting signs of peeling, blistering, or delamination to service without repairing or replacing the coating shall consider the potential impact on the intended function of the system. This evaluation shall include consideration of the potential for degraded performance of downstream components due to flow blockage and loss of material of the coated component. 14. Require the as-left condition of a coating that exhibited signs of peeling, blistering, or delamination and that is not repaired or replaced is such that the potential for further degradation of the coating is minimized. 15. Perform a minimum of 25 volumetric examinations of Fire Protection System piping, using radiographic testing or ultrasonic testing, during each 10-year interval.		
17	Aboveground Metallic Tanks	Aboveground Metallic Tanks is a new program that manages aging effects of loss of material and cracking on the external surfaces of aboveground metallic tanks within the scope of license renewal by performing periodic visual	Program to be implemented no later than six months prior to the	Section A.2.1.17 Exelon letter RS-14-003

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		inspections once per eighteen (18) month operating cycle for degradation of the external surface of the insulation lagging, flashing, roof, and accessible sealant. The program also requires periodic visual inspections and liquid penetrant examinations of the tank external surfaces at 25 locations for both tanks combined per site and includes, on a sampling basis, removal of selected tank lagging and insulation to permit inspections of the external tank surfaces and exposed sealants. The tank external surface inspections and examinations will be performed each 10-year period starting 10 years prior to the period of extended operation. The sample locations will include at least four locations below penetrations through the insulation and its jacketing (e.g. instrument nozzles, tank heaters, ladder). The remaining sample locations will be distributed such that inspections will occur on the tank dome, sides, and near the bottom. One-time tank bottom ultrasonic inspections (one CST per station) will be performed within the 5-year period prior to the period of extended operation. The cathodic protection availability and effectiveness criteria in LR-ISG-2011-03 Table 4c, notes 3.ii and 3.iii, respectively, will be required to be met commencing 5 years prior to the PEO and during the PEO.	period of extended operation. The pre-PEO inspection activities specified in the commitment will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	01/13/2014 RAI B.2.1.17-1 RAI B.2.1.17-2
18	Fuel Oil Chemistry	Fuel Oil Chemistry is an existing program that will be enhanced to: 1. Provide for the periodic cleaning of the Fire Protection Fuel Oil Storage Tank (Byron only) [Note 1]. 2. Provide for periodic draining of water from the Auxiliary Feedwater Day Tanks, Diesel Generator Day Tanks, Essential Service Water Make/Up Pump Fuel Oil	Program to be enhanced no later than six months prior to the period of extended operation. Pre-PEO inspections specified in Enhancement 7 will be completed either no later than six months prior to the	Section A.2.1.18 Exelon letter RS-14-124 05/05/2014 RAI 3.0.3-2a Exelon letter RS-14-175

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		Storage Tanks (Byron only) Note 2, and Fire Protection Fuel Oil Storage Tanks. 3. Include analysis for the levels of microbiological organisms in the Auxiliary Feedwater Day Tanks and Essential Service Water Make-up Pumps Diesel Oil Storage Tanks (Byron only) Note 2. 4. Include analysis for water and sediment content, particulate concentration, and the levels of microbiological organisms for the Diesel Generator Day Tanks. 5. Include analysis for water and sediment content and the levels of microbiological organisms for the Diesel Generator Fuel Oil Storage Tanks. 6. Include analysis for particulate concentration and the levels of microbiological organisms for the Fire Protection Fuel Oil Storage Tanks. 7. Include internal inspections of the Fire Protection Fuel Oil Storage Tanks at least once during the 10-year period prior to the period of extended operation, and at least once every 10 years during the period of extended operation. Each diesel fuel tank will be drained and cleaned, the internal surfaces visually inspected (if physically possible), and, if evidence of degradation is observed during inspections, or if visual inspection is not possible, these diesel fuel tanks will be volumetrically inspected. 8. Include monitoring and trending for the levels of microbiological organisms for the Auxiliary Feedwater Day Tanks and Essential Service Water Make-up Pumps Diesel Oil Storage Tanks (Byron only) Note 2. 9. Include monitoring and trending for water and sediment content, particulate	PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	06/30/2014 RAI 3.0.3-2b

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		concentration, and the levels of microbiological organisms for the Diesel Generator Day Tanks. 10. Include monitoring and trending for water and sediment content and the levels of microbiological organisms for the Diesel Generator Fuel Oil Storage Tanks. 11. Include monitoring and trending for total particulate concentration and the levels of microbiological organisms for the Fire Protection Fuel Oil Storage Tanks. 12. Require inspections of internal coatings be performed by coating inspectors certified to ANSI N45.2.6 or ASTM Standards endorsed in Regulatory Guide 1.54. 13. Specify that signs of peeling, blistering, or delamination of the coating from the base metal, if identified, shall be entered into the corrective action program. 14. Require physical testing of internal coatings, where physically possible, to ensure that remaining coating is tightly bonded to the base metal when peeling, blistering, or delamination is detected and the coating is not repaired or replaced. The testing will consist of adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., ASTM D4541-09 or ASTM D6677-07). 15. Require that evaluations utilized to return a coated component exhibiting signs of peeling, blistering, or delamination to service without repairing or replacing the coating shall consider the potential impact on the intended function of the system. This evaluation shall include consideration of the potential for degraded performance of		

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		downstream components due to flow blockage and loss of material of the coated component. 16. Require the as-left condition of a coating that exhibited signs of peeling, blistering, or delamination and that is not repaired or replaced is such that the potential for further degradation of the coating is minimized.		
19	Reactor Vessel Surveillance	Reactor Vessel Surveillance is an existing program that will be enhanced to: 1. Establish operating restrictions to ensure that the plant is operated under the conditions to which the surveillance capsules were exposed. The operating restrictions are as follows: Byron Station, Unit 1: - Cold leg operating temperature limitation: 525 degrees Fahrenheit (minimum) to 590 degrees Fahrenheit (maximum). - RPV beltline material fluence: 3.21E+19 n/cm2 (E >1.0 MeV) (maximum). Byron Station, Unit 2; Braidwood Station, Unit 1: - Cold leg operating temperature limitation: 525 degrees Fahrenheit (minimum) to 590 degrees Fahrenheit (maximum). - RPV beltline material fluence: 3.19E+19 n/cm2 (E >1.0 MeV) (maximum). Braidwood Station, Unit 2:	Program to be enhanced no later than six months prior to the period of extended operation. Specimen capsule testing to be performed in accordance with the schedule described in Enhancement 2.	Section A.2.1.19 Exelon Letter RS-14-002 01/13/2014 RAI B.2.1.19-1 Exelon Letter RS-14-149 05/23/2014 RAI B.2.1.19-1a Exelon Letter RS-14-225 07/28/2014 RAI B.2.1.19-1b

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		- Cold leg operating temperature limitation: 525 degrees Fahrenheit (minimum) to 590 degrees Fahrenheit (maximum). - RPV beltline material fluence: 3.16E+19 n/cm2 (E >1.0 MeV) (maximum). If the reactor pressure vessel exposure conditions (neutron fluence, neutron spectrum) or irradiation temperature (cold leg inlet temperature) are altered, then the basis for the projection to the end of the period of extended operation needs to be reviewed and, if deemed appropriate, updates are made to the Reactor Vessel Surveillance program. Any changes to the Reactor Vessel Surveillance program must be submitted for NRC review and approval in accordance with 10 CFR Part 50, Appendix H. 2. One (1) specimen capsule per reactor vessel, as designated below, irradiated to a neutron fluence of one (1) to two (2) times the projected peak neutron fluence at the end of the period of extended operation will be withdrawn from the spent fuel pool, tested, and the summary technical report submitted to the NRC within one (1) year of receipt of the renewed license. Alternatively, if a request for extension of the testing schedule is submitted in accordance with 10 CFR Part 50, Appendix H and granted by the Director, Office of Nuclear Reactor Regulation, specimen testing will be performed in accordance with that approved extension.		

<table>
<tr><th colspan="5">Table A.5-1 License Renewal Commitment List</th></tr>
<tr><th>NO.</th><th>PROGRAM OR TOPIC</th><th>COMMITMENT</th><th>IMPLEMENTATION SCHEDULE*</th><th>SOURCE</th></tr>
<tr><td></td><td></td><td>
<table>
<tr><th>Reactor Vessel (Station, Unit)</th><th>Capsule ID</th><th>Capsule Fluence (n/cm^2) (E>1.0 MeV)</th></tr>
<tr><td>Byron, Unit 1</td><td>Y</td><td>3.97E+19</td></tr>
<tr><td>Byron, Unit 2</td><td>Y</td><td>4.19E+19</td></tr>
<tr><td>Braidwood, Unit 1</td><td>V</td><td>3.71E+19</td></tr>
<tr><td>Braidwood, Unit 2</td><td>V</td><td>3.73E+19</td></tr>
</table>
</td><td></td><td></td></tr>
<tr><td>20</td><td>One-Time Inspection</td><td>One-Time Inspection is a new program that will be used to verify the system-wide effectiveness of the Water Chemistry, Fuel Oil Chemistry and Lubricating Oil Analysis programs.

The One-Time Inspection aging management program will also be utilized, in specific cases where existing data is insufficient:

a. to validate that a particular aging effect is not occurring, or

b. to verify that the aging effect is occurring slowly enough to not affect a components intended function during the period of extended operation.

In these cases, the components will not require additional aging management.</td><td>Program to be implemented no later than six months prior to the period of extended operation.

One-time inspections will be performed within the ten year period prior to the period of extended operation, and will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.</td><td>Section A.2.1.20

Exelon letter RS-14-003 01/13/2014

RAI B.2.1.23-1</td></tr>
<tr><td>21</td><td>Selective Leaching</td><td>Selective Leaching is a new program that will include one-time inspections of a representative sample of susceptible components to determine if loss of material due to selective leaching is occurring.</td><td>Program to be implemented no later than six months prior to the period of extended operation.

One-time inspections will be performed within the five (5) year period prior to the period of extended</td><td>Section A.2.1.21</td></tr>
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Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
			operation, and will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	
22	One-Time Inspection of ASME Code Class 1 Small-Bore Piping	One-Time Inspection of ASME Code Class 1 Small-Bore Piping is a new program that will manage the aging effect of cracking in Class 1 small-bore piping that is less than nominal pipe size (NPS) 4-inches, and greater than or equal to NPS 1-inch. The socket weld sample population for Byron Unit 1 will include the socket weld on the "D" safety injection system cold leg injection line that was replaced in 1998.	Program to be implemented no later than six months prior to the period of extended operation. One-time Inspections will be performed and evaluated within the six (6) year period prior to the period of extended operation, and will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	Section A.2.1.22 Exelon Letter RS-14-002 01/13/2014 RAI B.2.1.22-1
23	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components is a new program that manages aging effects of metallic and elastomeric materials through periodic visual inspection of external surfaces for evidence of loss of material and cracking. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers. The periodic system walkdowns include visual inspection of insulation jacketing to ensure the integrity of the jacketing is maintained. External visual inspections of the jacketing	Program to be implemented no later than six months prior to the period of extended operation.	Section A.2.1.23 Exelon letter RS-14-003 01/13/2014 RAI 2.1.23-1 RAI 3.0.3-3 Exelon letter

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		ensure that there is no damage to the jacketing that would permit in-leakage of moisture. The procedures for planning insulation repairs will be revised to document that insulation repairs are performed in accordance with specification requirements (e.g., seams on the bottom, overlapping seams) so as to prevent water intrusion into the insulation. Periodic representative inspections to detect corrosion (i.e., loss of material) under insulation will be conducted on in-scope indoor insulated components, where the process fluid temperature is below the dew point for a period of time sufficient to accumulate condensation, and in-scope outdoor insulated components (with the exception of the condensate storage tanks). These periodic inspections will be conducted during each 10-year period of the period of extended operation. Inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), then periodic visual inspections under insulation to detect corrosion and cracking under insulation will continue.		RS-14-051 02/27/2014 RAI 3.5.2-4 Exelon letter RS-14-218 07/18/2014
24	Flux Thimble Tube Inspection	Flux Thimble Tube Inspection is an existing program that will be enhanced as follows: 1. For Braidwood Units 1 and 2 (Note 3): Perform corrective actions to re-establish periodic eddy current testing of the flux	Byron: Ongoing Braidwood: Schedule for flux thimble tube replacement	Section A.2.1.24 Exelon letter RS-14-336 11/22/2014

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		thimble tubes prior to the period of extended operation to ensure that wall thickness is monitored to detect loss of material from the flux thimble tubes. Once periodic eddy current testing is re-established, eddy current testing will be performed for each flux thimble tube every refueling outage until sufficient data has been accumulated to establish a plant-specific eddy current testing frequency to ensure that no flux thimble tube is predicted to incur wear that exceeds 80% before the next inspection. Flux thimble tube wall thickness measurements will be trended and wear rates will be calculated based on plant-specific data. Wall thickness will be projected using plant-specific data in accordance with the WCAP-12866, "Bottom Mounted Instrumentation Flux Thimble Wear," methodology. 2. For Braidwood Unit 1 (Note 3): a. The 17 Braidwood Station, Unit 1 flux thimble tubes that exhibited indications of wear during eddy current testing performed during A1R15 Refueling Outage (Fall 2010), will be replaced or removed from service during A1R18 Refueling Outage (Spring 2015), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program. (Flux thimble tubes 1(J-8), 8(K-6), 9(H-11), 12(E-9), 14(H-4), 18(L-11), 19(L-5), 21(E-11), 23(D-10), 36(J-14), 37(P-9), 41(N-4), 44(R-8), 45(N-13), 48(P-4), 54(A-11), 55(N-14)) b. The remaining Braidwood Station, Unit 1 flux thimble tubes, not replaced during A1R18, will be replaced or removed from service during A1R19 Refueling Outage (Fall 2016), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program.	activities identified in commitment. Corrective actions to re-establish periodic eddy current testing at Braidwood will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later. Braidwood Unit 1: Commitment 2.a completed during A1R18 in Spring 2015	Exelon letter RS-15-071 02/23/15 Exelon letter RS-15-107 04/13/2015

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		c. Following A1R19, any Braidwood Station, Unit 1 flux thimble tube will be replaced every two (2) refueling outages or removed from service if eddy current data is not obtained in accordance with the Flux Thimble Tube Inspection program. 3. For Braidwood Unit 2 (Note 3): a. The 29 Braidwood Station, Unit 2 flux thimble tubes that exhibited indications of wear during eddy current testing performed during A2R15 Refueling Outage (Spring 2011) and not replaced during A2R17 Refueling Outage (Spring 2014), will be replaced or removed from service during A2R18 Refueling Outage (Fall 2015), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program. (Flux thimble tubes 1(J-8), 4(H-6), 5(F-8), 6(J-10), 7(F-7), 9(H-11), 10(L-8), 11(G-5), 18(L-11), 22(K-12), 23(D-10), 24(H-13), 25(N-8), 26(H-3), 27(C-8), 29(N-6), 32(L-13), 33(C-5), 34(H-2), 36(J-14), 37(P-9), 40(F-14), 41(N-4), 42(D-3), 45(N-13), 46(J-1), 50(R-6), 52(L-15), 56(N-2)) b. The remaining Braidwood Station, Unit 2 flux thimble tubes, not replaced during A2R17 or A2R18, will be replaced or removed from service during A2R19 Refueling Outage (Spring 2017), unless eddy current data is obtained as required by the Flux Thimble Tube Inspection program. c. Following A2R19, any Braidwood Station, Unit 2 flux thimble tube will be replaced every two (2) refueling outages or removed from service if eddy current data is not obtained in accordance with the Flux Thimble Tube Inspection program.		

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
25	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is a new program that manages aging effects of metallic and elastomeric materials through visual inspections of internal surfaces for evidence of loss of material. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers. This opportunistic approach is supplemented to ensure a representative sample of components within the scope of this program are inspected. At a minimum, in each 10-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each 10-year period despite meeting the sampling minimum requirement.	Program to be implemented no later than six months prior to the period of extended operation.	Section A.2.1.25 Exelon letter RS-14-003 01/13/2014 RAI B.2.1.25-1
26	Lubricating Oil Analysis	Existing program is credited.	Ongoing	Section A.2.1.26
27	Monitoring of Neutron-Absorbing Materials Other than Boraflex	Monitoring of Neutron-Absorbing Materials Other than Boraflex is an existing program that will be enhanced to: 1. Maintain the coupon exposure such that it is bounding for the Boral material in all spent fuel racks prior to coupons being examined, by ensuring that the coupons have been surrounded with a greater number of freshly discharged fuel assemblies than that of any other cell location.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.27 Exelon letter RS-14-052 03/04/2014 RAI B.2.1.27-1
28	Buried and Underground Piping	Buried and Underground Piping is an existing program that will be enhanced to:	Program to be enhanced no later than six months	Section A.2.1.28

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		1. Perform manual examinations, in addition to visual inspections, to detect hardening, softening, or other changes in material properties for buried polymeric piping (Braidwood only) Note 2. 2. Cracking will be managed for stainless steel components, utilizing a method that has been demonstrated to be capable of detecting cracking, whenever coatings are removed and expose the base material (Braidwood only) Note 2. 3. Ensure all underground carbon steel essential service water system piping within the scope of license renewal is coated in accordance with NACE SP0169-2007 prior to the period of extended operation (Byron only) Note 1. 4. Direct visual inspections of coated piping and components will be performed by an individual possessing a NACE Coating Inspector Program Level 2 or 3 operator qualification, or by an individual who has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course. 5. Inspection quantities of buried piping within the scope of license renewal will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4a, and based upon the as-found results of cathodic protection system availability and effectiveness during each ten year period, beginning 10 years prior to the period of extended operation. 6. The buried carbon steel condensate system piping within the scope of license renewal will be addressed, through means of a long term mitigation strategy, prior to entering the period of extended operation. Mitigation may include activities such as	prior to the period of extended operation. Pre-PEO activities specified in Enhancements 3, 5, 6 and 7 will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	Exelon letter RS-14-003 01/13/2014 RAI B.2.1.28-4 RAI B.2.1.28-3

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		fully recoating, complete replacement with like or upgraded material, installation of internal polymeric sleeves, and routing of pipe above ground or in an engineered trench for leak detection. Inspections of the condensate system piping will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4a, and based on the mitigation strategy implemented (Braidwood only) Note 3. 7. Inspection quantities of underground piping within the scope of license renewal will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4b, during each 10 year period, beginning 10 years prior to the period of extended operation. a. The piping and components inside the Byron 0SX138A and 0SX138B valve vaults will be visually inspected by engineering on a quarterly basis until either measures to prevent immersion of the piping and components inside the vault are implemented, or a coating system is installed that is designed for periodic immersion applications (Byron only) Note 3. 8. If adverse indications are detected during inspection, inspection sample sizes within the affected piping categories will be doubled. If adverse indications are found in the expanded sample, an analysis will be conducted to determine the extent of condition and extent of cause. The size of the follow-on inspections will be determined based on the analysis. Timing of the additional inspections will be based on the severity of the identified degradation and the consequences of leakage. In all cases, the additional inspections will be performed within the same 10-year inspection interval in which the original adverse indication was identified. Expansion of sample size may		

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		be limited by the extent of piping subject to the observed degradation mechanism. 9. In performing cathodic protection surveys, only the -850mV polarized potential criterion specified in NACE SP0169-2007 for steel piping will be used for acceptance criteria and determination of cathodic protection system effectiveness. Alternatively, soil corrosion, or electrical resistance, probes may also be used to demonstrate cathodic protection effectiveness during the annual surveys. An upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes will also be established, so as to preclude potential damage to coatings. 10. An extent of condition evaluation will be conducted if observed coating damage caused by non-conforming backfill has been evaluated as significant. The extent of condition evaluation will be conducted to ensure that the as-left condition of backfill in the vicinity of the observed damage will not lead to further degradation.		
29	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE is an existing program that will be enhanced to: 1. Provide guidance for specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. 2. Use the condition of the embedded reinforcing steel at the inner surface of the tendon tunnel as a representative indicator for the potential for corrosion at the exterior surface of the containment liner plate. Use the results of Structures Monitoring (B.2.1.34) aging management program, Enhancement 16 activities and results from ongoing examinations of the	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.29 Exelon Letter RS-14-183 7/8/2014 Updated response to RAI B.2.1.29-1

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		tendon tunnel performed as part of the ASME Section XI, Subsection IWL (B.2.1.30) and Structures Monitoring (B.2.1.34) aging management programs to identify changing conditions. Changing conditions consisting of the identification of significant corrosion of embedded steel in the tendon tunnel structure require an evaluation to determine if augmented examinations in accordance with requirements of IWE-1240 "Surface Areas Requiring Augmented Examination" are required due to the potential for accelerated corrosion at the exterior surface of the containment liner plate.		
30	ASME Section XI, Subsection IWL	ASME Section XI, Subsection IWL is an existing program that will be enhanced to: 1. Include additional augmented examination requirements after post-tensioning system repair/replacement activities in accordance with Table IWL-2521-2. 2. A one-time inspection of one (1) vertical and one (1) horizontal tendon on each unit will be performed prior to the period of extended operation. The inspection will consist of visually examining one (1) wire from each of the two (2) types of tendons at a worst-case location based on evidence of free water, grease discoloration, and grease chemistry results. This location will serve as a leading indicator for potential degradation or tendon surface corrosion. The visual inspection of these wires will be performed in accordance with existing station procedures used for inspections consistent with IWL-2523.2. The acceptance criteria will consist of each wire being free of any active corrosion, including general and pitting corrosion. In the event that the acceptance criteria are not met and corrosion is identified, the condition will be entered into the corrective action program. The condition will be evaluated	Program to be enhanced no later than six months prior to the period of extended operation. Pre-PEO inspections specified in Enhancements 2 and 3 will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	Section A.2.1.30 Exelon Letter RS-14-183 7/8/2014 Updated response to RAI B.2.1.30-3 Exelon Letter RS-14-328 11/21/2014 RAI B.2.1.30-6 Exelon Letter RS-14-216 12/15/2014

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		to characterize the corrosion, determine the cause of the corrosion, the location, depth, extent of the condition, and applicability of the condition to other wires that comprise that tendon. Corrective actions may include activities such as grease analysis, replacement of grease within the tendon duct, additional wire inspections from the same tendon, evaluation of the tendon capacity, potential replacement of the tendon, and augmented inspections and grease sampling of other leading indicator tendons, based, in part, on previous evidence of free water, observed grease leakage, grease discoloration, and grease chemistry results. Specific corrective actions will depend upon the cause, extent of condition, and grease properties. These corrective actions will be consistent with those actions which would be evaluated during periodic required IWL examinations (Braidwood only) Note 3. 3. In order to monitor for tendon exposure to free water and moisture and manage any potential adverse effects, a periodic tendon water monitoring and grease sampling program will be implemented (Braidwood only) Note 3. The program will consist of: a. A baseline inspection of tendon grease caps at the bottom of all vertical and dome tendons, as well as all below-grade horizontal tendons, prior to the period of extended operation. The baseline inspection will check for evidence of free water and grease discoloration, with further actions taken based on the condition of the grease. b. A follow-up tendon grease cap inspection of all vertical and dome tendons, as well as all below-grade horizontal tendons, will be performed within 10 years of the initial inspection, using		

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		the same approach as the baseline inspection. c. For those tendons where free water, moisture, and grease did not meet acceptance criteria during the two (2) previous inspections, periodic monitoring of grease chemistry and moisture, free water, and grease discoloration will be performed on a frequency not to exceed 10 years. Tendons, which exhibit significant quantities of free water (e.g., more than eight ounces) during periodic monitoring, will be inspected more often, with the timing of follow-up inspections increased until a frequency is achieved that no longer results in significant amounts of free water observed during successive inspections. Tendon water inspection and draining frequencies may vary from annual to every ten (10) years, depending upon grease chemistry and moisture parameters meeting IWL acceptance criteria. The maximum ten (10) year periodic frequency is meant to address any tendons which exhibit evidence of free water but the quantity is observed to be insignificant, with no observable grease discoloration, and given that the tendon wasn't inspected for at least ten (10) years prior. More frequent follow-up inspections will be performed for tendons which exhibit insignificant quantities of free water, but were inspected within the ten (10) years prior. In all cases, the frequency of inspections for water in individual tendons will be adjusted to be commensurate with the severity of the conditions found during each examination.		

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		d. Braidwood has performed augmented inspections on additional tendons beyond those selected for the ASME Section XI, Subsection IWL program. The Braidwood augmented inspections are performed on a 5 year frequency, in conjunction with the ASME Section XI, Subsection IWL aging management program. The current augmented examinations of additional tendons will continue until the periodic tendon water monitoring and grease sampling program described above is implemented. Corrective actions will be taken as necessary to ensure that the tendon grease meets ASME Section XI, Subsection IWL requirements 4. Explicitly require that areas of concrete deterioration and distress be recorded in accordance with the guidance provided in ACI 349.3R. The visual resolution capability of direct and remote examination techniques will be sufficient to detect concrete degradation at the levels described in Chapter 5 of ACI 349.3R. The resolution capability of the optical aids used for remote examinations will be demonstrated as equivalent to direct visual examination. 5. Include quantitative acceptance criteria, based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R, that will be used to augment the qualitative assessment of the Responsible Engineer. In addition, the Responsible Engineer will confirm that the visual resolution capability used for the concrete Containment Structure examinations was sufficient to evaluate the examination results against the quantitative acceptance criteria described in Chapter 5 of ACI 349.3R.		
31	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF is an existing program that will be enhanced to:	Program to be enhanced no later than six months	Section A.2.1.31

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		1. Add the MC supports for the transfer tube in the refueling cavity in the Containment Structure and refueling canal in the Fuel Handling Building to the scope of the program. 2. Revise implementing documents to provide guidance for proper specification of bolting material, storage, lubricants and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Bolting material with actual measured yield strength of 150 ksi or greater shall not be used in plant changes without engineering approval, due to consideration of stress corrosion cracking vulnerability. Storage requirements for high strength bolts shall include the recommendations of the Research Council for Structural Connections, “Specification for Structural Joints Using ASTM A325 or A490 Bolts”, Section 2. Lubricants that contain molybdenum disulfide (MoS_2) shall not be applied to high strength structural bolts within the scope of license renewal. 3. Provide procedural guidance, regarding the selection of supports to be inspected on subsequent inspections, when a support is repaired in accordance with the corrective action program. The enhanced guidance will ensure that the supports inspected on subsequent inspections are representative of the general population. 4. Perform one-time volumetric examinations on a sample of ASTM A490 bolts, greater than one-inch nominal diameter for the detection of stress corrosion cracking prior to the period of extended operation. Volumetric examinations will be performed in accordance with the requirements of ASME Code Section XI, Appendix VIII, Supplement 8. The sample will consist of bounding and representative A490 bolt sizes, joint configurations, and environmental exposure	prior to the period of extended operation. Pre-PEO examinations specified in Enhancements 4 and 5 will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	Exelon Letter RS-14-052 03/04/2014 RAIs B.2.1.31-1 B.2.1.31-2 B.2.1.31-3 Exelon Letter RS-14-170 06/16/2014 RAI B.2.1.31-1a Exelon Letter RS-14-235 08/29/2014

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		conditions. The sample will consist of 20% of the ASTM A490 bolts greater than one-inch nominal diameter or a maximum of 25 ASTM A490 bolts total for both Byron and Braidwood stations. The selection of the samples will consider susceptibility to stress corrosion cracking (e.g., actual measured yield strength) and ALARA principles. Any adverse results of the volumetric examinations will be entered into the corrective action program and will be evaluated by engineering to determine if additional actions are warranted such as expansion of sample size, scope, and frequency of any additional supplemental visual or volumetric examinations, as well as any code requirements specified by ASME Section XI, Subsection IWF. Specifically, the implementing documents for performing the one-time volumetric examinations will have criteria for extending the ASTM A490 bolt examination scope to other ASTM A490 bolts used in similar joint configurations and environmental exposure conditions if the volumetric examination of a bolt shows adverse results, which is similar to the methodology used by the ASME Code IWF-2430 for IWF component supports. In addition, the program will be revised to include periodic volumetric examinations, of ASTM A490 bolts in sizes greater than one-inch nominal diameter, if the one-time volumetric examination of an ASTM A490 bolt shows signs of cracking. The periodic examinations of the ASTM A490 bolts are included in the periodic examination of the supports. For the periodic examinations of supports, the population of the supports examined is specified in Table IWF-2500-1. Consistent with the GALL Report, the periodic examinations will include volumetric examinations of high-strength bolts to detect cracking, if required, in addition to the VT-3 examinations of the high-strength bolts.		

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		5. Revise implementing documents to perform periodic visual examinations to detect a corrosive environment that supports SCC potential for all (100%) of high strength bolting greater than one-inch nominal diameter prior to the period of extended operation, and then each inspection interval of 10 years thereafter. The periodic visual examinations will include criteria to identify if the bolting has been exposed to moisture or other contaminants by evidence of moisture, residue, foreign substance, or corrosion. Adverse conditions identified during the examinations will be evaluated by engineering to determine if the bolt has been exposed to a corrosive environment with the potential to cause SCC. The bolts determined to have been exposed to corrosive environment with the potential to cause SCC will be included in a sample population for each specific bolt material where SCC is a concern. A sample size equal to 20 percent (rounded up to the nearest whole number) of the bolts in the sample population, with a maximum sample size of 25 bolts will be subject to supplemental volumetric examination to determine if SCC is present. The selection of the samples will consider susceptibility to stress corrosion cracking (e.g., actual measured yield strength) and ALARA principles. Volumetric examinations will be performed in accordance with the requirements of ASME Code Section XI, Appendix VIII, Supplement 8. The results of the volumetric examinations will be evaluated by engineering to determine if additional actions are warranted such as expansion of sample size, scope, and frequency of any additional supplemental visual or volumetric examinations, as well as any code requirements specified by ASME Section XI, Subsection IWF. 6. Add the control rod drive mechanism seismic support assembly to the scope of the		

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		program to implement additional examinations.		
32	10 CFR Part 50, Appendix J	Existing program is credited.	Ongoing	Section A.2.1.32
33	Masonry Walls	Masonry Walls is an existing program that will be enhanced to: 1. Add masonry walls in the following structures to the program scope: a. Radwaste and Service Building Complex i. Radwaste Building ii. Original Service Building b. Turbine Building Complex c. Switchyard Structures i. Relay House 2. Provide additional guidance for inspection of masonry walls for shrinkage, separation, and for gaps between the supports and the masonry walls that could impact the intended function of the masonry walls. 3. Require that personnel performing inspections and evaluations meet the qualifications described in ACI 349.3R.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.33
34	Structures Monitoring	Structures Monitoring is an existing program that will be enhanced to: 1. Add the following structures: a. Radwaste and Service Building Complex i. Radwaste Building ii. Original Service Building b. Turbine Building Complex c. Yard Structures i. Transformer foundations ii. Valve and line enclosures d. Fire protection structures-features	Program to be enhanced no later than six months prior to the period of extended operation. Pre-PEO activities specified in Enhancement 16 will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage	Section A.2.1.34 Exelon Letter RS-13-274 12/19/2013 RAI 2.1-3 Exelon letter RS-14-097 04/17/2014 RAI B.2.1.34-1 Exelon letter

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		i. Transformer fire barrier walls ii. Fuel oil storage tank berm e. Containment structure features i. Containment access facility hallway 2. Add the following components and commodities: a. Blowout panels b. Building features - doors and seals, bird screens, louvers, windows c. Compressible joints and seals, gaskets and moisture barriers d. Concrete curbs e. Electrical cable trays, conduits and tube tracks f. Hatches and plugs g. Insulation including jacketing h. Manholes, handholes and duct banks i. Metal components, including metal decking for concrete slabs, miscellaneous steel, sump screens and trench covers, and scuppers around the spent fuel pool j. New fuel storage racks k. Offgas stack and flue l. Panels, racks, cabinets, and other enclosures m. Penetration seals and sleeves n. Pipe whip restraints, jet impingement shields, and spray shields	prior to the PEO, whichever occurs later.	RS-14-169 06/16/2014 RAI 3.5.2.10-1 Exelon Letter RS-14-216 12/15/2014

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		o. Pipe, electrical and equipment component support members p. Sliding surfaces q. Spent fuel pool gates r. Sumps and liners 3. Monitor groundwater chemistry on a frequency not to exceed five (5) years for pH, chlorides, and sulfates and evaluate results exceeding the threshold criteria to assess impact, if any, on below-grade concrete. 4. Based on groundwater chemistry monitoring results, select and inspect every five (5) years a structure that will be used as a leading indicator for the condition of below grade concrete exposed to groundwater. 5. Require (a) evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examination of representative samples of the exposed portions of the below grade concrete, when excavated for any reason. 6. Provide guidance for proper specification of high strength bolting material and lubricant to prevent or mitigate degradation and failure of structural bolting. 7. Revise storage requirements for high strength bolts to include recommendations of Research Council on Structural Connections (RCSC) Specification for Structural Joints Using High Strength Bolts, Section 2.0. 8. Clarify that loose bolts and nuts, and cracked high strength bolts are not		

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		acceptable unless accepted by engineering evaluations. 9. Include the potential for reduction in concrete anchor capacity due to local concrete degradation. 10. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R with respect to knowledge of in-service inspection of concrete and visual acuity requirements. 11. Require acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R. 12. Perform inspection of elastomeric components such as vibration isolation elements and structural seals for cracking, loss of material and hardening. Visual inspections of elastomeric components are to be supplemented by feel or manipulation to detect hardening. 13. Monitor accessible sliding surfaces to detect loss of mechanical function or significant loss of material due to wear, corrosion, debris, dirt, distortion, or overload that could restrict or prevent sliding of surfaces as required by design. 14. Formalize requirements for the monitoring of the leak detection sight glasses associated with the refuel cavity, transfer canal, spent fuel pool, and refueling water storage tank on a periodic basis. 15. Require visual inspections of submerged concrete structural elements by dewatering a structure or by a diver if the structure is not dewatered at least once every five (5) years (Byron only) [Note 2].		

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		16. At each site, perform one-time sampling activities on below grade, reinforced concrete at specific locations in the tendon tunnels. Select the locations exhibiting significant mineral deposits to serve as leading indicators for potential reinforced concrete degradation as a result of exposure to ground water in-leakage and build-up of mineral deposits. Take corrective actions, if necessary, prior to the period of extended operation. Perform the one-time sampling activities as follows: a. Obtain water in-leakage samples, at representative locations with mineral deposits due to water in-leakage, and analyze for pH, chlorides, sulfates, minerals, and iron content. b. Obtain representative mineral deposit samples and analyze for chemical composition. c. Remove three concrete core samples. i. Test two of the concrete core samples for compressive strength and perform petrographic examination of the core samples. Select representative locations for the concrete core samples that include one with significant mineral deposits and another at a location with no mineral deposits for comparative purposes. ii. Drill an additional core at a crack with significant mineral deposits and subject the core to petrographic examination. d. Expose and examine reinforcing steel at two locations, with water in-leakage, cracks, and significant mineral deposits.		

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		e. Collectively evaluate the results from the water in-leakage analysis, the chemical composition of the mineral deposits, examination of the exposed reinforcing steel, and the core sample testing to confirm there is no significant degradation to the reinforced concrete material properties and to determine if additional corrective actions are necessary. Additional corrective actions may include, but are not limited to, an extent of condition review for other potentially impacted structures, more frequent examinations, and additional sampling and analysis, as appropriate. 17. Perform visual inspections of polymeric components, such as blowout panels, for changes in material properties. Observations of material discoloration, cracking, crazing, and loss of material will provide visual indications of changes in material properties prior to a loss of component intended function.		
35	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants is an existing program that will be enhanced to: 1. Provide guidance for specification of structural bolting material and bolting lubricants to prevent or mitigate degradation and failure of structural bolting. 2. Revise storage requirements for structural bolting to include recommendations of Research Council on Structural Connections (RCSC) Specification for Structural Joints Using High Strength Bolts, Section 2.0. 3. Include the potential for reduction in concrete anchor capacity due to local concrete degradation.	The Byron Essential Service Water Cooling Tower inspection and maintenance plan (Enhancement 16) was initiated prior to receipt of the renewed licenses, and will continue through the period of extended operation to ensure the condition of the SXCT is maintained. The remainder of the enhancements will be implemented no later than six	Section A.2.1.35 Exelon Letter RS-14-216 12/15/2014

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		4. Include all aging affects addressed by ACI 349.3R in procedures and require acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R. 5. Clarify that loose bolts and nuts, and cracked bolts are not acceptable unless accepted by engineering evaluations. 6. Require that steel components subject to RG 1.127 are inspected for loss of material. 7. Require that inspectors work under the direction of a qualified engineer for submerged concrete inspections. 8. Require special inspections also be performed in the event of large floods, hurricanes, and intense local rainfalls. 9. Require increased inspection frequency if the extent of the degradation is such that the structure or component may not meet its design basis if allowed to continue uncorrected until the next normally scheduled inspection. 10. Require (a) evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examination of representative samples of the exposed portions of the below grade concrete, when excavated for any reason. 11. Monitor raw water and groundwater chemistry at least once every five (5) years for pH, chlorides, and sulfates and verify that it remains non-aggressive, or evaluate results exceeding criteria to assess impact, if any, on submerged concrete.	months prior to the period of extended operation.	

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		12. Based on groundwater chemistry monitoring results, select and inspect every five (5) years a structure that will be used as a leading indicator for the condition of below grade concrete exposed to groundwater. 13. Require visual inspections of submerged concrete structural components by dewatering a structure or by a diver if the structure is not dewatered at least once every five (5) years. Maintenance procedures will be enhanced to require opportunistic inspection of submerged concrete structures when they are dewatered and made accessible. 14. Require that degraded conditions be documented and trended until the condition is no longer occurring or until a corrective action is implemented. 15. Clarify parameters to be monitored and inspected at the Essential Service Water Cooling Towers to include visual inspection for loss of material and reduction of heat transfer for the cooling tower fill, and visual inspection with physical manipulation for change in material properties associated with the PVC drift eliminators and fiberglass support beams for the drift eliminators (Byron only) Note 2. 16. Manage the condition of the Byron Essential Service Water Cooling Towers (SXCTs) as follows: a. Monitor and trend inspection activities at the SXCTs on an increased frequency, with inspections of the entire tower, including inspections of the fill support beams and air-inlet framing, on a three (3) year interval. The recommendations in Chapter 5 of ACI 349.3R will be used for quantitative acceptance and evaluation criteria.		

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		b. Develop a repair plan to address degradation of the SXCTs with specific emphasis and consideration for the fill support beams. Repairs that are required will be scheduled based on a ranking of the condition observed and the potential for the degradation to progress or propagate.		
36	Protective Coating Monitoring and Maintenance Program	Protective Coating Monitoring and Maintenance Program is an existing program that will be enhanced to: 1. Add recurring work orders requiring Service Level I coating inspections every refuel outage. 2. Require qualification of coating inspectors to ASTM D 5498. 3. Require qualification of personnel in accordance with ASTM D 7108. 4. Incorporate guidance for inspection and maintenance of Service Level I coatings per Regulatory Guide 1.54 and impose ASTM D 5163-08 requirements for Service Level I coatings condition assessment, reporting, evaluation, and documentation. 5. Require thorough visual inspections of all coatings near sumps or screens associated with the Emergency Core Cooling System (ECCS) by the coatings inspector(s). 6. Specify instruments and equipment that may be needed for Service Level I coatings inspections.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.36
37	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage aging of the insulation material for non-EQ cables and connections. Accessible cables and connections located in adverse localized	Program to be implemented no later than six months prior to the period of extended operation.	Section A.2.1.37

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
	Qualification Requirements	environments will be visually inspected at least once every 10 years for indications of reduced insulation resistance, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination.	Initial inspections will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	
38	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits is a new program that will be used to manage aging of non-EQ cable and connection insulation of the in-scope portions of the radiation monitoring system (Byron and Braidwood) and the neutron monitoring inputs to the reactor protection system (Braidwood only) Note 2. Calibration and cable tests (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation condition) will be performed and results will be assessed for reduced insulation resistance prior to the period of extended operation and at least once every 10 years during the period of extended operation.	Program to be implemented no later than six months prior to the period of extended operation. Initial calibration, cable tests and evaluation of results will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	Section A.2.1.38 Exelon letter RS-14-030 02/04/2014 RAI B.2.1.38-2 RAI B.2.1.38-3
39	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage the aging effects and mechanisms of non-EQ, in scope, inaccessible power cables. Cables will be tested using one or more proven tests for detecting reduced insulation resistance of the cable’s insulation system. The cables will be tested at least once every 6 years. More frequent testing may occur based on test results and operating experience.	Program to be implemented no later than six months prior to the period of extended operation. First cable tests and manhole inspections will be completed either no later than six months prior to the PEO, or before the	Section A.2.1.39 Exelon letter RS-14-041 02/19/2014 RAI B.2.1.39-2

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		Periodic actions will be taken to prevent inaccessible cables from being exposed to significant moisture. Manholes associated with the cables included in this program will be inspected for water collection with subsequent corrective actions (e.g., water removal), as necessary. Prior to the period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant specific operating experience with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. Operation of dewatering devices, if installed, will be verified prior to any known or predicted heavy rain or flooding event. During the period of extended operation, the inspections will occur at least annually.	end of the last refueling outage prior to the PEO, whichever occurs later.	
40	Metal Enclosed Bus	Metal Enclosed Bus is an existing program that will be enhanced to: 1. Specify that a sample size of 20 percent of the accessible bolted connection population with a maximum sample size of 25 to be inspected for increased resistance of connection by measuring the connection resistance using a micro-ohmmeter. 2. Specify that the external surfaces of metal enclosed bus enclosure assemblies are to be inspected for loss of material due to general, pitting, and crevice corrosion. 3. Specify maximum allowed bus connection resistance values.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.2.1.40
41	Fuse Holders (Byron only) Note 2	Fuse Holders (Byron only) Note 2 aging management program is a new program that applies to fuse holders located outside of active devices that have been identified as susceptible to aging effects.	Program to be implemented no later than six months prior to the period of extended operation.	Section A.2.1.41

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		Fuse holders subject to increased resistance of connection or fatigue, will be tested, by a proven test methodology, at least once every 10 years for indications of aging degradation. Visual inspection is not part of this program.	Initial resistance tests will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	
42	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will implement one-time testing of a representative sample (20 percent with a maximum sample size of 25) of non-EQ electrical cable connections to ensure that either aging of metallic cable connections is not occurring or that the existing preventive maintenance program is effective such that a periodic inspection program is not required.	Program to be implemented no later than six months prior to the period of extended operation. One-time tests will be completed either no later than six months prior to the PEO, or before the end of the last refueling outage prior to the PEO, whichever occurs later.	Section A.2.1.42
43	Fatigue Monitoring	Fatigue Monitoring is an existing program that will be enhanced to: 1. Address the cumulative fatigue damage effects of the reactor coolant environment on component life by evaluating the impact of the reactor coolant environment on critical components for the plant identified in NUREG/CR-6260. Additional plant-specific component locations in the reactor coolant pressure boundary will be evaluated if they are more limiting than those considered in NUREG/CR-6260. 2. Monitor and track additional plant transients that are significant contributors to component fatigue usage.	Program to be enhanced no later than six months prior to the period of extended operation. Environmental fatigue evaluations will be completed no later than six months prior to the period of extended operation.	Section A.3.1.1 Exelon letter RS-14-002 01/13/2014 RAI B.3.1.1-2

Table A.5-1 License Renewal Commitment List				
NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		3. Evaluate the effects of the reactor coolant system water environment on the reactor vessel internal components with existing fatigue CUF analyses to satisfy the evaluation requirements of ASME Code, Section III, Subsection NG-2160 and NG-3121. 4. Increase the scope of the program to include transients used in the analyses for ASME Section III fatigue exemptions, the allowable stress analyses associated with ASME Section III and ANSI B31.1, and the flaw evaluation analyses performed in accordance with ASME Section XI, IWB-3600.		
44	Concrete Containment Tendon Prestress	Concrete Containment Tendon Prestress is an existing program that will be enhanced to: 1. For each surveillance interval, the predicted lower-limit, minimum required value, and trending lines will be developed for the period of extended operation as part of the regression analysis for each tendon group.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.3.1.2
45	Environmental Qualification (EQ) of Electric Components	The Environmental Qualification (EQ) of Electric Components aging management program will be enhanced: 1. To expand the scope of the program to include mechanical environmental qualification (MEQ) components.	Program to be enhanced no later than six months prior to the period of extended operation.	Section A.3.1.3 Exelon letter RS-14-079 03/04/2014 RAI 4.7.3-1
46	Operating Experience	The Operating Experience Program is an existing program that will be enhanced to: 1. Require the review of internal and external operating experience for aging-related degradation or impacts to aging management activities, to determine if improvements to Byron and Braidwood Units 1 and 2 aging management activities are warranted. NRC and industry guidance documents and standards applicable to aging management are considered part of this information (e.g., License Renewal Interim Staff	Program was enhanced prior to receipt of the renewed operating licenses, and will be conducted on an ongoing basis throughout the terms of the renewed licenses.	Section A.1.6

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		Guidance (LR-ISG) documents, NUREG-1801 (GALL) revisions, etc.) Ensure there are written expectations for identifying and processing these documents as operating experience. 2. Establish criteria to define aging-related degradation. In general, the criteria will be used to identify aging that is in excess of what would be expected, relative to design, previous inspection experience and the inspection intervals. 3. Establish identification coding within the corrective action program for use in identification, trending and communications of aging-related degradation. Provide a definition for the coding. This coding will assist plant personnel in ensuring that, in addition to addressing the specific issue, the adequacy of existing aging management programs is assessed. Station personnel are required to periodically assess the performance of the aging management programs, including insights obtained through operating experience. Adverse trends are entered into the corrective action program for evaluation. This could lead to AMP revisions or the establishment of new AMPs, as appropriate. 4. Require communication of significant internal aging-related degradation, associated with SSCs in the scope of license renewal, to other Exelon plants and to the industry. Criteria will be established for determining when aging-related degradation is significant. 5. Provide training to those responsible for screening, evaluating and communicating operating experience items related to aging management and aging-related degradation. This training will be commensurate with their role in the process, will be provided periodically and include provisions to		

Table A.5-1 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE*	SOURCE
		accommodate personnel turnover.		
47	Byron Unit 2 Reactor Head Closure Stud Configuration (Byron only) Note 3	Byron Unit 2 reactor head closure stud location 11 will be repaired so that all 54 reactor head closure studs are tensioned during the period of extended operation.	Complete.	Exelon letter RS-13-285 12/19/2013 RAI B.2.1.3-2 updated response Exelon letter RS-14-216 12/15/2014 Exelon letter RS-15-035 01/23/2015
48	Braidwood Unit 2 Reactor Head Closure Stud Configuration (Braidwood only) Note 3	Braidwood Unit 2 reactor head closure stud location 35 will be repaired so that all 54 reactor head closure studs are tensioned during the period of extended operation.	No later than six months prior to the period of extended operation.	Exelon letter RS-13-285 12/19/2013 RAI B.2.1.3-2 updated response Exelon letter RS-14-216 12/15/2014 Exelon letter RS-15-035 01/23/2015
49	CRDM Housing Wear Analysis	DELETED.	Not Applicable.	Exelon letter RS-15-049 01/28/2015 Exelon letter RS-15-067 02/11/2015

* The dates for the start of the respective periods of extended operation for the Byron and Braidwood Units are:

Byron Unit 1: October 31, 2024
Bryon Unit 2: November 6, 2026
Braidwood Unit 1: October 17, 2026
Braidwood Unit 2: December 18, 2027

Exelon letter RS-14-216, responding to NRC RAI A.1-1, resulted in refining commitment implementation timing requirements as shown throughout the above table, in order to provide time for NRC inspection of commitment implementation prior to the plants entering their respective periods of extended operation.