APPENDIX B AGING MANAGEMENT PROGRAMS
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B.1 INTRODUCTION

B.1.1 OVERVIEW

License renewal Aging Management Program (AMP) descriptions are provided in this appendix for each program credited for managing aging effects based upon the Aging Management Review (AMR) results provided in Sections 3.1 through 3.6 of this application.

In general, there are four (4) types of AMPs:

- Prevention programs preclude aging effects from occurring.
- Mitigation programs slow the effects of aging.
- Condition monitoring programs inspect/examine for the presence and extent of aging.
- Performance monitoring programs test the ability of a structure or component to perform its intended function.

More than one type of AMP may be implemented for a component to ensure that aging effects are managed.

Part of the demonstration that the effects of aging are adequately managed is to evaluate credited programs and activities against certain required attributes. Each of the AMPs described in this section has ten (10) elements which are consistent with the attributes described in Appendix A.1, “Aging Management Review – Generic (Branch Technical Position RLSB-1)” and in Table A.1-1 “Elements of an Aging Management Program for License Renewal” of NUREG-1800. The 10-element detail is not provided when the program is deemed to be consistent with the assumptions made in NUREG-1801. The 10-element detail is only provided when the program is plant specific.

Credit has been taken for existing plant programs whenever possible. As such, all programs and activities associated with a system, structure, component, or commodity grouping were considered. Existing programs and activities that apply to systems, structures, components, or commodity groupings were reviewed to determine whether they include the necessary actions to manage the effects of aging.

Existing plant programs were often based on a regulatory commitment or requirement, other than aging management. Many of these existing programs included the required license renewal 10-element attributes, and have been demonstrated to adequately manage the identified aging effects. If an existing program did not adequately manage an identified aging effect, the program was enhanced as necessary. Occasionally, the creation of a new program was necessary.

B.1.2 METHOD OF DISCUSSION

For those AMPs that are consistent with the assumptions made in Sections X and XI of NUREG-1801, or are consistent with exceptions, each program discussion is presented in the following format:

- A Program Description abstract of the overall program form and function is provided.
- A NUREG-1801 Consistency statement is made about the program.
- Exceptions to the NUREG-1801 program are outlined and a justification for the exceptions is provided.
- Enhancements or additions to the NUREG-1801 program are provided. A proposed schedule for completion is discussed.
- Operating Experience (OE) information specific to the program is provided.
- A Conclusion section provides a statement of reasonable assurance that the program is effective, or will be effective, once enhanced.

For those AMPs that are plant specific, the above form is followed with the additional discussion of each of the 10-elements.

B.1.3 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 non-safety related systems, structures, and components (SSCs) that are subject to AMR. In many cases, existing activities were found adequate for managing aging effects during the period of extended operation. Generically the three elements are applicable as follows:

Corrective Actions:

A single corrective actions process is applied regardless of the safety classification of the system, structure, or component. Corrective actions are implemented through the initiation of an Issue Report (IR) in accordance with the Corrective Action Program established in response to 10 CFR 50, Appendix B. The Corrective Action Program requires the initiation of an Issue Report for actual or potential problems, including unexpected plant equipment degradation, damage, failure, malfunction or loss. Site documents that implement aging management programs for license renewal will direct that an Issue Report be prepared in accordance with those procedures whenever non-conforming conditions are found (i.e., the acceptance criteria are not met). It is noted that previous Corrective Action Programs referred to Condition Reports (CRs) or CAPs for documenting actual or potential problems and non-conforming conditions. These terms are synonymous with the term Issue Report.

Equipment deficiencies are corrected through the Work Control Program in accordance with plant procedures. Although equipment deficiencies may initially be documented by the Work Control Program, the Corrective Action Program specifies that an Issue Report also be initiated, if required, for condition identification, assignment of significance level and investigation class, investigation, corrective action determination, investigation report review and approval, action tracking, and trend analysis.

The Corrective Action Program implements the requirements of the Exelon Quality Assurance Topical Report (QATR), Chapter 16, “Corrective Action.” Specifically, Conditions Adverse to Quality and Significant Conditions Adverse to Quality are resolved through direct action, the implementation of Corrective Actions, and where appropriate, the implementation of Corrective Actions to Prevent Recurrence.

Confirmation Process:

The focus of the confirmation process is on the follow-up actions that must be taken to verify effective implementation of corrective actions. The measure of effectiveness is in terms of correcting and precluding repetition of adverse conditions. The Corrective Action Program includes provisions for timely evaluation of adverse conditions and implementation of any corrective actions required, including root cause determinations and prevention of recurrence where appropriate (e.g., Significant Conditions Adverse to Quality). The Corrective Action Program provides for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure effective corrective actions are taken. The Corrective Action Program also monitors for potentially adverse trends. The existence of an adverse trend due to recurring or repetitive adverse conditions will result in the initiation of an Issue Report. The AMPs required for license renewal would also uncover any unsatisfactory condition due to ineffective corrective action.

Since the same 10 CFR 50, Appendix B corrective actions and confirmation process is applied for nonconforming safety-related and nonsafety-related systems, structures, and components subject to Aging Management Review (AMR) for license renewal, the Corrective Action Program is consistent with the NUREG-1801 elements.

Administrative Controls:

The document control process applies to all generated documents, procedures, and instructions regardless of the safety classification of the associated system, structure, or component. Document control processes are implemented in accordance with the requirements of 10 CFR 50, Appendix B, “Quality Assurance Requirements for Nuclear Power Plants and Fuel Reprocessing Plants.” Implementation is further defined in the Exelon Quality Assurance Topical Report (QATR), Chapter 6, “Document Control.”

Administrative controls procedures provide information on procedures, instructions and other forms of administrative control documents, as well as guidance on classifying these documents into the proper document type and as-building frequency. Revisions will be made to procedures and instructions that implement or administer aging management program requirements for the purposes of managing the associated aging effects for the period of extended operation.

B.1.4 OPERATING EXPERIENCE

Operating experience is used in two ways at Three Mile Island Nuclear Station Unit 1 to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Three Mile Island Nuclear Station Unit 1. The first way in which operating experience is used is through the Three Mile Island Nuclear Station Unit 1 Operating Experience process (OPEX). The Operating Experience process screens, evaluates, and acts on operating experience documents and information to prevent or mitigate the consequences of similar events. The second way is through the process for managing programs. This process requires the review of program related operating experience by the program owner.

Both of these processes review operating experience from external and internal (also referred to as in-house) sources. External operating experience may include such things as INPO documents (e.g., SOERs, SERs, SENs, etc.), NRC documents (e.g., GLs, LERs, INs, etc.), and other documents (e.g., 10 CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B corrective action process.

Each AMP summary in this appendix contains a discussion of operating experience relevant to the program. This information was obtained through the review of in-house operating experience captured by the Corrective Action Program, Program Self-Assessments, and Program Health Reports, and through the review of primarily post-2005 industry operating experience (industry operating experience prior to 2005 having been addressed by Revision 1 to NUREG-1801). Additionally, operating experience was obtained through interviews with system and program engineers. The operating experience in each AMP summary identifies past corrective actions that have resulted in program enhancements and provides objective evidence that the effects of aging have been, and will continue to be, adequately managed.

B.1.5 NUREG-1801 CHAPTER XI AGING MANAGEMENT PROGRAMS

The following AMPs are described in the sections listed in this appendix. The programs are either generic in nature as discussed in NUREG-1801, Section XI, or are plant-specific. NUREG-1801 Chapter XI programs are listed in Section B.2.1. Plant-specific programs are listed in Section B.2.2. All generic programs are fully consistent with or are, with some exceptions, consistent with programs discussed in NUREG-1801. Programs are identified as either existing or new.

1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B.2.1.1) [Existing]

2. Water Chemistry (Section B.2.1.2) [Existing]
3. Reactor Head Closure Studs (Section B.2.1.3) [Existing]
4. Boric Acid Corrosion (Section B.2.1.4) [Existing]
5. Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (Section B.2.1.5) [Existing]
6. Flow-Accelerated Corrosion (Section B.2.1.6) [Existing]
7. Bolting Integrity (Section B.2.1.7) [Existing]
8. Steam Generator Tube Integrity (Section B.2.1.8) [Existing]
9. Open-Cycle Cooling Water System (Section B.2.1.9) [Existing]
10. Closed-Cycle Cooling Water System (Section B.2.1.10) [Existing]
11. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section B.2.1.11) [Existing]
12. Compressed Air Monitoring (Section B.2.1.12) [Existing]
13. Fire Protection (Section B.2.1.13) [Existing]
14. Fire Water System (Section B.2.1.14) [Existing]
15. Aboveground Steel Tanks (Section B.2.1.15) [Existing]
16. Fuel Oil Chemistry (Section B.2.1.16) [Existing]
17. Reactor Vessel Surveillance (Section B.2.1.17) [Existing]
18. One-Time Inspection (Section B.2.1.18) [New]
19. Selective Leaching of Materials (Section B.2.1.19) [New]
20. Buried Piping and Tanks Inspection (Section B.2.1.20) [Existing]
21. External Surfaces Monitoring (Section B.2.1.21) [New]
22. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.1.22) [New]
23. Lubricating Oil Analysis (Section B.2.1.23) [Existing]
24. ASME Section XI, Subsection IWE (Section B.2.1.24) [Existing]
25. ASME Section XI, Subsection IWL (Section B.2.1.25) [Existing]
26. ASME Section XI, Subsection IWF (Section B.2.1.26) [Existing]

27. 10 CFR Part 50, Appendix J (Section B.2.1.27) [Existing]
28. Structures Monitoring Program (Section B.2.1.28) [Existing]
29. Protective Coating Monitoring and Maintenance Program (Section B.2.1.29) [Existing]
30. Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.30) [New]
31. Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section B.2.1.31) [Existing]
32. Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.32) [New]
33. Metal Enclosed Bus (Section B.2.1.33) [Existing]
34. Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.34) [New]
35. Nickel Alloy Aging Management Program (Section B.2.2.1) [Existing]

B.1.6 NUREG-1801 CHAPTER X AGING MANAGEMENT PROGRAMS

The following NUREG-1801 Chapter X AMPs are described in Section B.2.3 of this appendix as indicated. Programs are identified as either existing or new.

1. Metal Fatigue of Reactor Coolant Pressure Boundary (Section B.3.1.1) [Existing]
2. Concrete Containment Tendon Prestress (Section B.3.1.2) [Existing]
3. Environmental Qualification (EQ) of Electrical Components (Section B.3.1.3) [Existing]

B.2 AGING MANAGEMENT PROGRAMS

B.2.0 NUREG-1801 AGING MANAGEMENT PROGRAM CORRELATION

The correlation between the NUREG-1801 (Generic Aging Lessons Learned (GALL)) programs and the Three Mile Island Nuclear Station Unit 1 Aging Management Programs (AMPs) is shown below. Links to the sections describing the Three Mile Island Nuclear Station Unit 1 NUREG-1801 programs are provided.

NUREG-1801 NUMBER	NUREG-1801 PROGRAM	THREE MILE ISLAND NUCLEAR STATION UNIT 1 PROGRAM
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B.2.1.1)
XI.M2	Water Chemistry	Water Chemistry (Section B.2.1.2)
XI.M3	Reactor Head Closure Studs	Reactor Head Closure Studs (Section B.2.1.3)
XI.M4	BWR Vessel ID Attachment Welds	Not Applicable (BWR)
XI.M5	BWR Feedwater Nozzle	Not Applicable (BWR)
XI.M6	BWR Control Rod Drive Return Line Nozzle	Not Applicable (BWR)
XI.M7	BWR Stress Corrosion Cracking	Not Applicable (BWR)
XI.M8	BWR Penetrations	Not Applicable (BWR)
XI.M9	BWR Vessel Internals	Not Applicable (BWR)
XI.M10	Boric Acid Corrosion	Boric Acid Corrosion (Section B.2.1.4)
XI.M11	Nickel-Alloy Nozzles and Penetrations	Not used. This AMP has been replaced in part by XI.M11A, Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program (Section B.2.1.5). Guidance for the aging management of other nickel-alloy nozzles and penetrations is provided in the AMR line items of Chapter IV and is addressed by the plant specific Nickel Alloy Aging Management Program (Section B.2.2.1).
XI.M11A	Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (Section B.2.1.5)
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Not used. The loss of fracture toughness in pump casings and valve bodies due to thermal aging embrittlement is managed by XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (Section B.2.1.1).
XI.M13	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	Not used. The UFSAR Supplement commitment for PWR Vessel Internals (see XI.M16) will be used to manage Loss of Fracture Toughness/Thermal Aging and Neutron Irradiation Embrittlement for the cast austenitic stainless steel vessel internals.
XI.M14	Loose Part Monitoring	Not used. Not credited for aging management.
XI.M15	Neutron Noise Monitoring	Not used. Not credited for aging management.

NUREG-1801 NUMBER	NUREG-1801 PROGRAM	THREE MILE ISLAND NUCLEAR STATION UNIT 1 PROGRAM
XI.M16	PWR Vessel Internals	TMI-1 will provide a commitment in the UFSAR supplement to (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, an inspection plan for reactor internals will be submitted to the NRC for review and approval.
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (Section B.2.1.6)
XI.M18	Bolting Integrity	Bolting Integrity (Section B.2.1.7)
XI.M19	Steam Generator Tube Integrity	Steam Generator Tube Integrity (Section B.2.1.8)
XI.M20	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (Section B.2.1.9)
XI.M21	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System (Section B.2.1.10)
XI.M22	Boraflex Monitoring	Not used. Not credited for aging management.
XI.M23	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 (Section B.2.1.11)
XI.M24	Compressed Air Monitoring	Compressed Air Monitoring (Section B.2.1.12)
XI.M25	BWR Reactor Water Cleanup System	Not Applicable (BWR)
XI.M26	Fire Protection	Fire Protection (Section B.2.1.13)
XI.M27	Fire Water System	Fire Water System (Section B.2.1.14)
XI.M28	Buried Piping and Tanks Surveillance	Not Used. The aging effects associated with buried piping and tanks are managed by XI.M34, Buried Piping and Tanks Inspection program (Section B.2.1.20).
XI.M29	Aboveground Steel Tanks	Aboveground Steel Tanks (Section B.2.1.15)
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry (Section B.2.1.16)
XI.M31	Reactor Vessel Surveillance	Reactor Vessel Surveillance (Section B.2.1.17)
XI.M32	One-Time Inspection	One-Time Inspection (Section B.2.1.18)
XI.M33	Selective Leaching of Materials	Selective Leaching of Materials (Section B.2.1.19)

NUREG-1801 NUMBER	NUREG-1801 PROGRAM	THREE MILE ISLAND NUCLEAR STATION UNIT 1 PROGRAM
XI.M34	Buried Piping and Tanks Inspection	Buried Piping and Tanks Inspection (Section B.2.1.20)
XI.M35	One-Time Inspection of ASME Code Class 1 Small Bore-Piping	Not Used. The aging effect of cracking in ASME Code Class 1 small bore-piping due to thermal and mechanical loading or intergranular stress corrosion is managed by XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (Section B.2.1.1).
XI.M36	External Surfaces Monitoring	External Surfaces Monitoring (Section B.2.1.21)
XI.M37	Flux Thimble Tube Inspection	Not used. Not credited for aging management.
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.1.22)
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis (Section B.2.1.23)
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE (Section B.2.1.24)
XI.S2	ASME Section XI, Subsection IWL	ASME Section XI, Subsection IWL (Section B.2.1.25)
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF (Section B.2.1.26)
XI.S4	10 CFR Part 50, Appendix J	10 CFR Part 50, Appendix J (Section B.2.1.27)
XI.S5	Masonry Wall Program	Not used. The aging effects associated with masonry walls are managed by XI.S6, Structures Monitoring Program (Section B.2.1.28).
XI.S6	Structures Monitoring Program	Structures Monitoring Program (Section B.2.1.28)
XI.S7	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Not used. The aging effects associated with water-controlled structures are managed by XI.S6, Structures Monitoring Program (Section B.2.1.28).
XI.S8	Protective Coating Monitoring and Maintenance Program	Protective Coating Monitoring and Maintenance Program (Section B.2.1.29)
XI.E1	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.30)

NUREG-1801 NUMBER	NUREG-1801 PROGRAM	THREE MILE ISLAND NUCLEAR STATION UNIT 1 PROGRAM
XI.E2	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section B.2.1.31)
XI.E3	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.32)
XI.E4	Metal Enclosed Bus	Metal Enclosed Bus (Section B.2.1.33)
XI.E5	Fuse Holders	Not used. The metallic clamp portions of fuse holders have no aging effects requiring management.
XI.E6	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 (Section B.2.1.34)
X.M1	Metal Fatigue of Reactor Coolant Pressure Boundary	Metal Fatigue of Reactor Coolant Pressure Boundary (Section B.3.1.1)
X.S1	Concrete Containment Tendon Prestress	Concrete Containment Tendon Prestress (Section B.3.1.2)
X.E1	Environmental Qualification (EQ) of Electrical Components	Environmental Qualification (EQ) of Electrical Components (Section B.3.1.3)
N/A	Three Mile Island Nuclear Station Unit 1 plant specific program	Nickel Alloy Aging Management Program (Section B.2.2.1)

B.2.1 NUREG-1801 CHAPTER XI AGING MANAGEMENT PROGRAMS

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

B.2.1.1 ASME SECTION XI INSERVICE INSPECTION, SUBSECTIONS IWB, IWC, AND IWD

Program Description

The TMI-1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is an existing program that is part of the Inservice Inspection (ISI) program and includes inspections performed to manage cracking and loss of fracture toughness in Class 1, 2, and 3 piping and components within the scope of license renewal. The program provides for the periodic visual, surface, and volumetric examination and leakage testing of pressure-retaining piping and components including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting. The program includes an alternate method approved in accordance with 10 CFR 50.55a which is used to determine the inspection locations, inspection frequency, and inspection techniques for Class 1 Category B-F and B-J, and Class 2 Category C-F-1 and C-F-2 welds in accordance with 10 CFR 50.55a(a)(3)(i). This method also addresses volumetric examination of welds less than NPS 4 inches.

In accordance with 10 CFR 50.55a(g)(4)(ii), the TMI-1 ISI program is updated each successive 120 month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval.

NUREG-1801 Consistency

The TMI-1 Inservice Inspection aging management program is an existing program that is consistent with NUREG-1801 aging management program XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD with the exceptions described below.

Exceptions to NUREG-1801

- NUREG-1801 specifies the 2001 ASME Section XI B&PV Code, including the 2002 and 2003 Addenda for Subsections IWB, IWC, and IWD. The TMI-1 ISI Program Plan for the third ten-year inspection interval effective from April 20, 2001 through April 19, 2011, approved per 10 CFR 50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for TMI-1 will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval.
- NUREG-1801 specifies the use of ASME Section XI B&PV Code, which includes requirements for examining Class 1 Category B-F and B-J, and Class 2 C-F-1 and C-F-2 piping components. At TMI-1, an alternate method approved in accordance with 10 CFR 50.55a is used to determine the inspection frequency for Class 1 Category B-F and B-J, and Class 2 Category C-F-1 and C-F-2 welds in accordance with 10 CFR 50.55a(a)(3)(i) by alternatively providing an acceptable level of quality and safety. This method also addresses volumetric examination of welds less than NPS 4

inches. Other portions of the ASME Section XI ISI program outside of this scope remain unaffected.

Enhancements

None.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that cracking due to stress corrosion cracking, cracking due to thermal and mechanical loading, cracking due to cyclic loading, and loss of fracture toughness due to thermal aging embrittlement are being adequately managed. The following examples of operating experience provide objective evidence that the TMI-1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. In 2002, a nuclear oversight assessment of non-destructive examination (NDE) procedures governed by the ISI program discovered an inspection procedure that was not updated to reflect the currently applicable ASME Code and Addenda editions as referenced in the ISI program. A review was performed to determine any effect from citing the earlier code, and an extent of condition review was performed to ascertain the existence of any similar incorrect code date use. This example provides objective evidence that deficiencies in the ISI program are identified and entered into the corrective action process and that the program is updated as necessary to ensure that it remains effective for condition monitoring of piping and components within the scope of license renewal.

2. An NDE examination of a pressurizer surge line safe-end to surge nozzle weld in 2003 identified an indication of a single axial flaw within the nozzle butter or weld metal. The indication was evaluated and repaired via the corrective action process. The evaluation determined the most likely cause to be primary water stress corrosion cracking (PWSCC), and an expanded scope of examination of similar type welds was performed in accordance with code requirements, with no further indications found. The subject weld was added to the schedule for UT examination for the next two outages, after which it is returned to its normal schedule for examination. This example provides objective evidence that the program provides appropriate guidance for inspection and evaluation, that deficiencies are entered into the corrective action process, and that appropriate action (expansion of scope due to observed conditions) is taken as necessary to ensure effective condition monitoring of piping and components within the scope of license renewal.

3. In 2005, a focused-area self assessment of the TMI-1 ISI program identified improvement items for completeness of program documentation including referencing an NRC-issued SER for a weld repair in the program, referencing an NRC-issued SER addressing certification of VT-2 examiners in the program, and including information from the repair and replacement program in the work order used as the repair plan. These changes were made in revisions to the program documents and implemented by the work planners. This example provides objective evidence that deficiencies in the ISI program are identified and entered into the corrective action process and that the program is updated as necessary to ensure that it remains effective for condition monitoring of piping and components within the scope of license renewal.

4. A nuclear oversight audit in 2006 identified three work order repair plans for code-required VT-2 examinations that did not adequately document post-maintenance inspections per the requirements of ASME Section XI, specifically the system test temperature, pressure, hold time, and acceptance criteria for insulated, non-insulated, and buried components. The documentation of post-maintenance test (PMT) activities was determined to be adequate for routine maintenance activities, but did not meet ASME code requirements in the three plans identified. Implementing guidance on performing and documenting VT-2 examinations were reviewed and revised as necessary, with library copies of repair plan work orders revised to clearly reflect VT-2 examination documentation requirements. This example provides objective evidence that deficiencies are identified and entered into the corrective action process and that the program is updated as necessary to ensure that it remains effective for condition monitoring of piping and components within the scope of license renewal.

In 631 examinations performed under the TMI-1 Section XI Inservice Inspection program from 2001 through 2005, only two did not return a satisfactory result and required material repair.

Conclusion

The continued implementation of the TMI-1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program provides reasonable assurance that the aging effects of cracking and loss of fracture toughness will be adequately managed so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation.

B.2.1.2 WATER CHEMISTRY

Program Description

The TMI-1 Water Chemistry aging management program is an existing program that provides activities for monitoring and controlling the chemical environments of the TMI-1 primary cycle and secondary cycle systems such that aging effects of system components are minimized. Aging effects include cracking, denting, loss of material, reduction of heat transfer, and reduction of neutron-absorbing capacity. The primary cycle scope of this program consists of the reactor coolant system and related auxiliary systems containing reactor coolant (borated treated water), including the primary side of the steam generators. The secondary cycle portion of the program consists of various secondary side systems and the secondary side of the steam generators. Major component types include reactor vessel, reactor internals, heat exchangers, pumps casing, boiler casings, filter housings, tanks, valve bodies, piping, and piping components. The Water Chemistry aging management program is consistent with EPRI 1002884, Pressurized Water Reactor Primary Chemistry Guidelines, Revision 5 and Plant Technical Specification limits for fluorides, chlorides, and dissolved oxygen. The Water Chemistry program will be enhanced to become consistent with EPRI 1008224, Pressurized Water Reactor Secondary Water Chemistry Guidelines, Revision 6. This enhancement will incorporate the continuous monitoring of sodium in steam generator blowdown.

Industry experience has shown water chemistry programs may not be effective in low flow or stagnant flow areas of plant systems. Therefore, components located in such areas at TMI-1 will receive a one-time visual inspection. This inspection will be performed as part of the TMI-1 One-Time Inspection (B.2.1.18) aging management program.

NUREG-1801 Consistency

The Water Chemistry Program is consistent with the ten elements of aging management program XI.M2, “Water Chemistry Program”, specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

The TMI-1 Water Chemistry Program will be enhanced to include the continuous monitoring of steam generator blowdown for sodium during startup and hot standby conditions as required by EPRI 1008224, PWR Secondary Water Chemistry Guidelines, Revision 6. This enhancement will be implemented after replacement of the existing once-through steam generators and prior to the period of extended operation for TMI-1.

Operating Experience

The Water Chemistry aging management program is a preventative program that assures contaminants are maintained below applicable limits to prevent the aging of plant piping and components. Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that cracking, denting, loss of material, reduction of heat transfer, and reduction of neutron-absorbing capacity are being adequately managed. The following examples of operating experience provide objective evidence that the TMI-1 Water Chemistry aging management program will be effective in assuring that intended functions will be maintained consistent with the current licensing bases for the period of extended operation:

1. In June 2002, feedwater sodium levels exceeding the Action Level 1 values of 1 ppb were identified. This was the only occurrence of a chemistry action level being exceeded at TMI-1 in the past five years. Investigation identified the cause of the sodium increase as a condenser tube leak on the “B” side of the main condenser. Corrective actions included securing the moisture separator drains, rapid replacement of Powdex vessels, reduction of power to 50%, and location and repair of the failed condenser tube. Prompt action to identify the cause of the high sodium level, and repair the tube led to the reduction of feedwater sodium below 1ppb within one day of discovery. This example provides objective evidence that a) deficiencies found during water chemistry monitoring activities are documented in the corrective action process, and b) water chemistry monitoring activity deficiencies are evaluated and corrective actions are properly implemented to maintain system intended functions.

2. A focused area self-assessment (FASA) of the TMI-1 Water Chemistry program was performed in March 2004. The objective of the FASA was to determine if procedures are in place for monitoring and controlling RCS chemistry. Specifically, procedure CY-AP-120-105, “Reactor Coolant System Chemistry for Three Mile Island” was reviewed against the requirements of current EPRI PWR Primary Water Chemistry Guidelines. The review identified dissolved oxygen action limits in the procedure that were inconsistent with the EPRI guidelines. The FASA verified that these differences were appropriately documented in an issue report and that appropriate procedure revisions were drafted. However, the revised procedure had not been issued at the time of the FASA. The FASA also revealed that procedure CY-AP-120-105 did not require documentation when diagnostic parameters varied from the EPRI guidelines. FASA recommendations called for this to be documented in the future as an industry best practice. Revised procedure CY-AP-120-105, incorporating these changes, was issued subsequent to the FASA. Documentation of RCS chemistry excursions, including lithium and dissolved oxygen values above action levels, was determined appropriate. No voluntary entries into actions levels occurred during this time period. Finally, the FASA included the observation of RCS sampling being conducted by a

chemistry technician to assess proper performance and radiation control practices. No deficiencies associated with the sampling process were identified. This example provides objective evidence that a) assessments are performed to verify the effectiveness of program execution, b) deficiencies are documented in the corrective action process, and c) assessment deficiencies are evaluated and corrective actions implemented to maintain program effectiveness.

3. In May 2006, routine water chemistry monitoring identified a high chloride concentration in the reactor coolant system (RCS). The chloride level exceeded the plant administrative goal of 20 ppb for RCS chlorides, but was below the level 1, 2, and 3 limits, established in accordance with the EPRI PWR Primary Water Chemistry Guidelines and Technical Specifications. A plant event and/or an incorrect analytical result were ruled out as causes of the condition. TMI site and corporate chemistry staffs participated in identifying the cause of the higher-than-goal chloride concentration as chloride elution from the in-service make-up and purification demineralizer. Multiple recovery options were considered. The chosen recovery plan called for replacing the resin in the make-up and purification demineralizer and returning it to service to remove chlorides from the RCS. An engineering review was performed to ensure the effectiveness of the plan. The corrective actions were implemented and the chloride concentration was successfully reduced below the administrative goal. This example provides objective evidence that a) deficiencies found during water chemistry monitoring activities are documented in the corrective action process, and b) water chemistry monitoring activity deficiencies are evaluated and corrective actions are properly implemented to maintain system intended functions.

Conclusion

The enhanced Water Chemistry aging management program, supplemented by the One-Time Inspection Program (B.2.1.18), provides reasonable assurance that cracking, denting, loss of material, reduction of heat transfer, and reduction of neutron-absorbing capacity aging effects will be managed such that the systems and components with the scope of the program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

B.2.1.3 REACTOR HEAD CLOSURE STUDS

Program Description

The Reactor Head Closure Studs Aging Management Program is an existing program that provides for ASME Section XI inspections of reactor head closure studs and stud components to identify and manage cracking due to stress corrosion cracking, and loss of material due to wear, general, pitting and crevice corrosion. The program is implemented through station procedures based on the examination and inspection requirements specified in ASME Section XI Table, IWB-2500-1 and preventive measures described in NRC Regulatory Guide 1.65, "Materials and Inspection for Reactor Vessel Closure Studs."

NUREG-1801 Consistency

The Reactor Head Closure Studs Aging Management Program is consistent with NUREG-1801 Section XI.M3, Reactor Head Closure Studs, with the following exceptions:

Exceptions to NUREG-1801

- NUREG-1801, XI.M3, specifies the 2001 ASME Section XI B&PV Code, including the 2002 and 2003 Addenda. The current TMI-1 ISI Program Plan for the third ten-year inspection interval effective from April 20, 2001 through April 19, 2011, approved per 10 CFR 50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for TMI-1 will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval.
- NUREG-1801, X1.M3, specifies that surface examination uses magnetic particle, liquid penetration, or eddy current examinations to indicate the presence of surface discontinuities and flaws in the reactor head closure studs. The current TMI-1 ISI program for the third interval does not require surface examination. The next 120-month inspection interval for TMI-1 will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval.

Enhancements

None.

Operating Experience

The Reactor Head Closure Studs Aging Management Program is implemented through the ASME Section XI, Subsections IWB, IWC and IWD, ISI Program that monitors the condition of the closure studs and stud components. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, and by inclusion the Reactor Head Closure Studs Program, is implemented and maintained in accordance with the general requirements for engineering programs. This provides assurance that the programs are effectively implemented to meet regulatory, process, and procedure requirements, including periodic reviews; qualified personnel are assigned as program managers, and are given authority and responsibility to implement the program; and adequate resources are committed to program activities.

A search of condition reports and ISI history was conducted, and no reports documenting deficiencies or problems with reactor head closure studs or stud components, or the Reactor Head Closure Studs Program, were found. The following examples of operating experience provide objective evidence that the Reactor Head Closure Studs program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. Reactor Closure Head Studs and Bolts 21 through 40 were UT and VT-1 examined during the Fall of 2005 with no reportable indications.

2. Reactor Closure Head Studs and Bolts 41 through 60 were UT, MT and VT-1 examined during the Fall of 2003 with no reportable indications.

3. Reactor Closure Head Studs and Bolts 41 through 60 were UT and MT examined during the Fall of 1999 with no reportable indications.

4. Reactor Closure Head Studs and Bolts 1 through 20 were MT examined in the Fall of 1991, and UT examined in the Fall of 1993 with no reportable indications.

Based on these results, the operating experience provides evidence that the ASME Section XI, Subsections IWB, IWC and IWD, ISI Program and maintenance practices are ensuring the continuing integrity of the reactor head closure studs and stud components.

Conclusion

The Reactor Head Closure Studs program provides reasonable assurance that cracking and loss of material aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.4 BORIC ACID CORROSION

Program Description

The Boric Acid Corrosion aging management program is an existing program that provides for management of loss of material due to boric acid corrosion. The program includes provisions to identify, inspect, examine and evaluate leakage, and initiate corrective action. The program relies in part on implementation of recommendations of NRC Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Components in PWR plants” and includes visual examinations of Alloy 600 components for stress corrosion cracking due to boric acid leakage.

NUREG-1801 Consistency

The TMI-1 Boric Acid Corrosion program is an existing program that is consistent with NUREG-1801 aging management program XI.M10, Boric Acid Corrosion.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

Industry operating experience indicates that boric acid leakage can cause significant corrosion damage to susceptible plant structures and components. The performance indicators for the TMI-1 Boric Acid Corrosion program show that the program is compliant with existing regulations and will be able to manage boric acid corrosion during the period of extended operation.

1. In November 2006, an active borated water leak was identified dripping from a reactor coolant valve threaded fitting. The leak produced boron crystal buildup on the fitting, piping, and grating below the fitting. The threaded fitting was repaired and the fitting and target piping and grating were cleaned. No degradation due to the borated water leakage was identified. The fitting was inspected again and no further leaking was detected.

2. Wet boron buildup was discovered in November 2006 on a differential pressure transmitter and other target components. The source of the leak was from a weeping relief valve through a stainless steel tailpipe onto grating, a stainless steel transmitter, and the concrete floor. The general area where the boric acid leak was occurring was inspected and no corrosion was observed. The majority of the components are stainless steel. There was no significant corrosion concern for the carbon steel components

because of the ambient conditions. The leak from the relief valve (MU-V-158D) was repaired and the target areas were cleaned.

3. In November 2005, corrosion on the Reactor Building Emergency Cooling flanges (both the normal supply and drain lines) was detected. Samples of the material in the flange areas were obtained but the chemistry analysis did not positively indicate any boron in the material. It was assumed that the source of the leakage may have been from an old reactor coolant pump leak several years before. The boric acid would have been diluted to the point that it could not be found in the samples. The leakage caused only surface corrosion and the affected areas were cleaned.

4. A Focused Area Self Assessment (FASA) of the Boric Acid Corrosion program was performed in December 2005. The FASA team evaluated areas including procedure compliance and technical rigor, program implementation effectiveness, program continuous improvement, program organization and human performance, and compliance to regulatory requirements. The FASA team concluded that TMI's performance in all areas reviewed was satisfactory. The team noted no deficiencies, fourteen recommendations for improvement, and one strength. Recommendations are tracked and evaluated for inclusion into the program. This example provides objective evidence that the program is updated as necessary to ensure that it remains effective for condition monitoring of structures and components within the scope of license renewal.

The operating experience of the Boric Acid Corrosion program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Boric Acid Corrosion program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the Boric Acid Corrosion program are performed to identify the areas that need improvement to maintain the quality performance of the program.

Conclusion

The existing Boric Acid Corrosion program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of structures and components within the scope license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.5 NICKEL-ALLOY PENETRATION NOZZLES WELDED TO THE UPPER REACTOR VESSEL CLOSURE HEADS OF PRESSURIZED WATER REACTORS

Program Description

The program for Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (Upper Head Nickel Alloy AMP) is an existing program that was developed by TMI-1 to respond to NRC Order EA-03-009. The Upper Head Nickel Alloy AMP provides for the management of cracking due to PWSCC in nickel-alloy vessel head penetration nozzles and includes the reactor vessel closure head, upper vessel head penetration nozzles and associated welds.

Detection of cracking, including cracking induced by PWSCC, is accomplished through implementation of a combination of bare metal visual examination and non-visual examination techniques. Examinations are performed by VT-2 certified personnel. Inspections completed to date have indicated no evidence of PWSCC in the vessel head penetration nozzles. Evaluations from the Fall 2005 refueling outage show a susceptibility ranking of "Low." Since TMI-1 replaced the head in 2003, the EA 03-009 ranking is “Replaced,” however the inspection requirements for “Low” and “Replaced” are the same. Plants in the "Low" or “Replaced” category require bare metal visual inspections at least once every third refueling outage or every five years, whichever comes first, and ultrasonic, eddy current, or dye penetrant testing every fourth refueling outage or every seven years, whichever comes first. Non-destructive examinations of the reactor pressure vessel head penetration nozzles and associated welds were performed on the new head prior to the Fall 2003 refueling outage when the reactor vessel upper head was replaced.

NUREG-1801 Consistency

The TMI-1 Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors aging management program is consistent with the ten elements of NUREG-1801 aging management program XI.M11A, Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors.

Exceptions to NUREG-1801

None.

Enhancements

None.

Operating Experience

PWSCC is occurring in the VHP nozzles of U.S. PWRs, as described in the program description above. In addition, applicants for license renewal should reference plant-specific operating experience that is applicable to PWSCC of its VHP nozzles. Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that PWSCC of upper VHP nozzles is being adequately managed. The following examples of operating experience provide objective evidence that the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. During the Fall 2005 refueling outage, minor boric acid deposits were visible during the video inspection at three CRD flanges. Deposits were dry with no significant buildup, and deposit colors were white and brown. Several dry semi-translucent boron drops were seen on the CRDM nozzles. No boron leakage targets were noted, and the deposits were small enough that they had not migrated beyond the flanges. No degradation was evident on the CRD surfaces. The video results were reviewed and the conditions noted for comparison during subsequent inspections.

   The VT-2 inspection report identified evidence of leakage from above with no boron noted at the flange areas. Based on this VT-2 report and supporting video, the leakage locations were not considered to be bolted flange connection leaks and did not require repair.

   The inspection found evidence of possible leakage at the CRD flanges, the issue was entered into and evaluated by the Corrective Action Process. As a result, one flange was reworked and no further leakage was found.

2. During the Fall 2005 refueling outage, a thin white film or streaking of boron was observed starting from the upper portion of the reactor head surface near a CRDM nozzle and running eastward to the lower/outer portion of the reactor head. Still photos were taken of the affected area. Two CRDMs had minor boron film running down from the above insulation. The insulation around the two CRDM nozzles and along nearby insulation seams had a heavier film of boron. The remaining reactor head bare metal surfaces did not have any other indication of boric acid staining. No indication of any corrosion was seen. The site performed one hundred percent VT-2 inspection of the reactor vessel head. The leakage appeared to be coming from an active Intermediate Closed Cooling water leak.

   One of the CRDM venting locations is a CRDM that was identified with boron staining. Inspections previously identified water on the reactor head insulation just east of the venting CRDMs that corresponded to the area directly above the noted reactor head bare metal streaks. TMI-1 performed visual examination of remaining portions of reactor head bare metal surfaces and CRDM nozzles and no other evidence of leakage was observed. The site also researched the previous refueling outage history for previous leakage at the reactor head area.

TMI-1 then performed an augmented ISI visual examination of the bolted CRDM flange connection when the reactor head was on the storage stand. Boron staining/film was cleaned to the extent possible to eliminate confusion during future bare metal reactor vessel head examinations. The gasket was replaced on one drive, and no further leakage was found.

3. A visual inspection of the Reactor Vessel Head Control Rod Drive Mechanism (CRDM) nozzle penetrations was performed in October 2001 (prior to replacement of the RPV head in the fall of 2003). From the visual inspection, twelve (12) CRDM nozzles were categorized as "suspect" due to residual boric acid deposits around the base of the nozzles. These "suspect" CRDM nozzles were subsequently examined using liquid penetrant testing (PT) and ultrasonic testing (UT) to obtain additional information for determination of through-wall nozzle defects. PT indications were identified on the j-groove weld associated with four CRDM nozzles.

   An ultrasonic test (UT) of a Reactor Vessel Head Control Rod Drive Mechanism (CRDM) nozzle penetration was performed on October 19, 2001. The UT results indicated that the CRDM nozzle had 5 inner diameter (ID) flaws, none of which were through-wall. This nozzle had no J-groove weld PT indication.

   This condition is consistent with industry experience with Primary Water Stress Corrosion Cracking (PWSCC) in reactor vessel head nozzles that have been evaluated as part of the NRC Generic Letter 97-01 and NRC Bulletin 2001-01. Reactor Vessel Head CRDM nozzle repair plans were developed and implemented prior to restart. The issue was self identified from visual, PT, and UT inspections of the Reactor Vessel Head nozzle penetrations (CRDM). A modification was designed to repair CRDM nozzles. CRDM nozzles were repaired as prescribed. Subsequently, the RPV head was replaced in Fall 2003.

The operating experience of the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the program are performed to identify the areas that need improvement to maintain the quality performance of the program.

Conclusion

The TMI-1 Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors aging management program is credited for managing PWSCC of upper VHP nozzles.

The continued implementation of the TMI-1 Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors aging management program provides reasonable assurance that PWSCC of upper VHP nozzles will be adequately managed so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation.

B.2.1.6 FLOW-ACCELERATED CORROSION

Program Description

The Flow-Accelerated Corrosion (FAC) aging management program is an existing program that is based on EPRI guidelines in NSAC-202L-R3, “Recommendations for an Effective Flow Accelerated Corrosion Program.” The program provides for predicting, detecting, and monitoring wall thinning in piping, fittings, valve bodies, and feedwater heaters due to FAC.

Analytical evaluations and periodic examinations of locations that are most susceptible to wall thinning due to FAC are used to predict the amount of wall thinning in pipes, fittings, and feedwater heater shells. Program activities include analyses to determine critical locations, baseline inspections to determine the extent of thinning at these critical locations, and follow-up inspections to confirm the predictions. Inspections are performed using ultrasonic, radiographic, visual or other approved testing techniques capable of detecting wall thinning. Repairs and replacements are performed as necessary.

NUREG-1801 Consistency

Program activities are consistent with the elements of aging program XI.M17, "Flow-Accelerated Corrosion," specified in NUREG-1801 with the following exception:

Exceptions to NUREG-1801

NUREG-1801 specifies in XI.M17 that the program relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R2 for an effective FAC program. The TMI-1 FAC Program is based on the EPRI guidelines found in NSAC-202L-R3. The sections of NSAC-202L associated with the program elements were reviewed to show that revision 2 and 3 of the guidelines are equivalent with one difference: revision 3 allows an additional method for determining the wear of piping components from UT inspection. This method is called the Averaged Band Method. TMI-1 does not use this method at this time.

Enhancements

None.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that wall thinning due to flow-accelerated corrosion is being adequately managed. The following examples of operating experience provide objective evidence that the Flow-Accelerated Corrosion program will be effective in assuring that intended function(s) would be maintained consistent with the CLB for the period of extended operation:

1. During the 2003 refueling outage, FAC inspections of several components were found to be thin. These components were analyzed to establish a safe life expectancy until 2005. These components were replaced in 2005. In addition, some components were experiencing high wear rates and were changed to a resistant material in 2005. Detailed stress analysis was performed to determine if the components would have to be changed out then or could last until the next outage in 2007. The FAC program manager stated that these components have been evaluated using the FAC evaluation model and are acceptable for continued service until the next refueling outage. The FAC program manager initiated the necessary ARs to include these items into the scope for 2007.

2. While at the semi-annual CHECKWORKS user group meeting in 2005 the FAC program manager performed benchmarking activities. Numerous areas for improvement and areas for consideration were noted. All benchmarking items were incorporated into the FAC Notebook. Items were assessed and action taken on items applicable to TMI-1. Specific items dealt with subjects like weld degradation, low temperature FAC, margins, purchase of Cr (chromium) Analyzer and improved accuracy in wear predictions from single point data.

3. A FAC component in the line from the heater drain pump discharge to the main feedwater pump suction header was found thin. This FAC component was examined in 2005 as part of the remedial actions due to the high fluid velocities experienced in this line when the valve was isolated. This component has a predicted wear rate of 5.3 mils per year. This wear rate prediction is based on one set of data and an assumed starting point for the original wall thickness. It was determined this wear rate extended over the next two years would require 10.6 mils more than the required minimum thickness. With the current minimum thickness value this component would not make it to 2007. A calculation for wear rate and the use of code case N-513 was applied. The component was found to be acceptable until 2007 with code case N-513 applied.

4. TMI-1 added to the FAC program scope the Main Feedwater Pump (MFP) recirculation lines in 2003. Wall thinning was found in the MFP recirculation lines in 2003 and 2005. The source of wear in the MFP recirculation lines was not caused by FAC. Repairs have been made to the lines.

The operating experience of the Flow-Accelerated Corrosion program did not show any adverse trend in performance. The FAC Program prediction capability at TMI-1 has been successful in finding wear early enough so that the repairs can be scheduled in a future outage. Also, no system or large bore (4" and greater) failures have been experienced due to FAC. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Flow-Accelerated Corrosion program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the Flow-Accelerated Corrosion program are performed to identify the areas that need improvement to maintain the quality performance of the program.

Conclusion

The FAC aging management program provides reasonable assurance that wall thinning aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.7 BOLTING INTEGRITY

Program Description

The Bolting Integrity aging management program is an existing program that provides for condition monitoring of pressure retaining bolted 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 TR-104213, “Bolted Joint Maintenance & Applications Guide,” and EPRI NP 5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” as part of the comprehensive corporate component pressure retaining bolting program. The program provides for managing the loss of material due to general, pitting and crevice corrosion, microbiologically influenced corrosion and loss of preload due to thermal effects, gasket creep, and self-loosening, by performing visual inspections for pressure retaining bolted joint leakage. Inspection of ASME Class 1, 2, and 3 components is conducted in accordance with ASME Section XI. Non-Class 1, 2, and 3 component inspections rely on detection of visible leakage during routine observations and equipment maintenance activities. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and torque are applied. The activities are implemented through station procedures. Other aging management programs also manage inspection of bolting and supplement this bolting integrity program. Structural bolting is managed as part of the Structures Monitoring aging management program. TMI does not use structure bolting with yield strength of greater than or equal to 150 ksi. Containment pressure retaining bolting is addressed by ASME Section XI, Subsection IWE, B.2.1.24. ASME Section XI, Subsection IWF aging management program, B.2.1.26, addresses aging management of ASME Section Class 1,2 & 3 piping and component supports. The aging management of crane and hoist bolting is covered by B.2.1.11, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems. Aging Management of heating and ventilation bolted joints is coved by B.2.1.21, External Surfaces Monitoring.

NUREG-1801 Consistency

The Bolting Integrity aging management program is consistent with the ten elements of aging management program XI.M18, "Bolting Integrity," specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

None.

Operating Experience

TMI-1 has experienced isolated cases of bolt corrosion, loss of bolt preload and bolt torquing issues. Review of operating history has not identified any cracking of stainless steel bolting. In all cases, the existing inspection and testing methodologies have discovered the deficiencies and corrective actions were implemented prior to loss of system or component intended functions.

1. Boron deposits were discovered on a partially insulated Make-up valve bonnet. The leak was not active at the time. One visible bonnet bolt had mild corrosion. A work activity was generated to remove the insulation and clean, inspect and correct as needed. Engineering inspected and determined that the necessary repair is replacement of the diaphragm gasket, and replacement of the bonnet studs if there has been any wastage. Work requires the system to be out of service and is scheduled for the next outage.

2. During an In-service Test (IST) run for Decay Heat Removal pump two issues were discovered. One involved the mechanical seal nuts. One of the four nuts did not have positive thread engagement. The second issue involved a loose nut on the pump frame. An Engineering evaluation of thread engagement and stress on the pump confirmed that the 3 fully engaged nuts provided adequate strength to hold the mechanical seal firmly in place when holding against maximum internal pressure. An assessment was made of 10 Condition Reports (CR's) for extent of condition for thread engagement. Information found during the investigation phase has been shared within maintenance. Specific attention was placed on recognition of issues as well as ensuring appropriate engagement is occurring during ongoing maintenance activities.

3. The emergency diesel generator exhaust manifold leaked oil on both control side and opposite control side of the engine. The manifolds leaked more than normal amounts of oil for approximately 3-4 days after the diesel was operated. The amount of leakage increased on both diesels after 1-2 runs on the new manifold gaskets. All bolts were visually checked to ensure full engagement via extent of condition checks on both diesels.

The operating experience of the Bolting Integrity program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Bolting Integrity program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the Bolting Integrity program are performed to identify the areas that need improvement to maintain the quality performance of the program.

Conclusion

The Bolting Integrity aging management program provides reasonable assurance that aging effects are adequately managed so that the intended functions of bolting for pressure retaining joints within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.8 STEAM GENERATOR TUBE INTEGRITY

Program Description

The Steam Generator Tube Integrity program is an existing program that establishes the operation, maintenance, testing, inspection and repair of the steam generators to ensure that Technical Specification surveillance requirements, ASME Code requirements and the Maintenance Rule performance criteria are met. The program provides for identifying, maintaining and protecting the steam generator design and licensing bases and implements NEI 97-06. NEI 97-06 establishes a framework for prevention, inspection, evaluation, repair and leakage monitoring measures.

TMI-1 will replace the original Once-Through Steam Generators (OTSGs) with enhanced OTSGs prior to the period of extended operation. This decision was made based on industry and TMI-1 experience with tube degradation. The new OTSGs have improved design features including Alloy 690 tubes. The new OTSGs will have a design life of 40 years, which along with the Steam Generator Tube Integrity program will be effective in assuring that the intended functions will be maintained consistent with the CLB for the period of extended operation. The Steam Generator Tube Integrity program will continue when the new OTSGs are installed. The Steam Generator Tube Integrity program implements NEI 97-06 and the TMI-1 Technical Specification Surveillance Requirements, and is equally applicable to OTSGs with degraded tubes and to the new OTSGs.

NUREG-1801 Consistency

The Steam Generator Tube Integrity Aging Management Program is an existing program that is consistent with NUREG-1801 aging management program XI.M19, Steam Generator Tube Integrity.

Exceptions to NUREG-1801

None.

Enhancements

None. The existing Steam Generator Tube Integrity program will be applied as described for the new OTSGs.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that cracking due to stress corrosion cracking, including intergranular attack, denting due to corrosion of carbon steel tubesheet, and loss of material due to fretting and wear are being adequately managed. The following examples of operating experience provide objective evidence that the Steam Generator Tube Integrity program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. Widespread inside diameter intergranular attack (ID IGA) was identified in the early 1980s, mostly near the upper end of the OTSG tubing. The degradation was determined to have occurred during a chemistry excursion while the plant was in a shutdown condition. Repairs were performed using a kinetic expansion process that formed a new tube to tubesheet joint within the upper tubesheet. The repair was reviewed and approved by the NRC in 1983. Since that time, TMI-1 has specified inspection acceptance criteria and leakage assessment methodology for the TMI-1 OTSG kinetic expansion joints that is unique to TMI-1. This inspection acceptance criteria and leakage assessment methodology has been reviewed and accepted by the NRC. During refueling outage 16 (Fall 2005), the kinetic expansion joints were inspected. These inspections found no growth of flaws in the kinetic expansion joints, and no trend of ongoing degradation due to ID IGA.

2. TMI-1 will replace the OTSGs with enhanced OTSGs prior to the period of extended operation. This decision was made based on industry and TMI-1 experience with tube degradation. During refueling outage 16 (Fall 2005), 100 tubes in A OTSG and 106 tubes in B OTSG were plugged due to unacceptable indications. The inspections during this outage concluded that groove IGA, primary water stress corrosion cracking (PWSCC), outside diameter stress corrosion cracking (OD SCC) are active damage mechanisms. The results of TMI-1 tube inspections indicate increasing tube degradation and the probability of mid-cycle outages for inspection prior to the end of the current license. Currently, the A OTSG has 1661 plugged tubes and 247 sleeved tubes are in service. The B OTSG has 971 plugged tubes and 252 sleeved tubes are in service. The degradation mechanisms that have been identified historically in the current OTSGs include PWSCC, ID IGA, Intergranular stress corrosion cracking (IGSCC), outside diameter intergranular attack (OD IGA), High Cycle Fatigue, OD SCC, Tube-to-Tube Support Plate Wear Fretting and Severed Plugged Tube-to-Tube wear. However, the overall tube integrity meets all of the requirements of the current licensing basis. The new OTSGs will have a design life of 40 years, which along with the Steam Generator Tube Integrity program will be effective in assuring that the intended functions will be maintained consistent with the CLB for the period of extended operation.

3. TMI-1 has incorporated a Technical Specification change to implement the requirements of Generic Letter 2006-01 and the associated alternative Technical Specification requirements for ensuring tube integrity. Generic Letter 2006-01 required that all PWRs implement the alternative Technical Specification requirements or submit a description of their program for ensuring tube integrity. The Generic Letter indicated that existing Technical Specifications may not be sufficient to ensure that steam generator tube integrity can be maintained in accordance with current

licensing and design basis. The revised Technical Specifications incorporate improved methodology based on NEI 97-06.

The operating experience of the TMI-1 Steam Generator Tube Integrity program has shown objective evidence that the program has identified degradation mechanisms in the steam generator and been effective in preventing failures prior to the loss of system intended function. There is sufficient confidence that the implementation of the Steam Generator Tube Integrity program will continue to effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the Steam Generator Tube Integrity program are performed to identify the areas that need improvement to maintain the quality performance of the program.

Conclusion

The Steam Generator Tube Integrity program provides reasonable assurance that cracking and loss of material aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.9 OPEN-CYCLE COOLING WATER SYSTEM

Program Description

The TMI-1 Open-Cycle Cooling Water System aging management program is an existing program.

The GL 89-13 activities provide for management of aging effects in raw water cooling systems through tests and inspections per the guidelines of NRC Generic Letter 89-13. System and component testing, visual inspections, NDE (RT, UT, and/or ECT-Eddy Current Testing), and chemical treatment are conducted to ensure that aging effects are managed such that system and component intended functions and integrity are maintained.

The TMI-1 Open-Cycle Cooling Water System (OCCWS) aging management program (AMP) primarily consists of station GL 89-13 activities that include chemical and biocide injection, system testing, periodic inspections and NDE. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the OCCW system or structures and components serviced by the OCCW system. Other activities include station maintenance inspections, component preventive maintenance (PM), plant surveillance testing, ISI, and inspections. These activities provide for management of loss of material (without credit for protective coatings) and buildup of deposit (including fouling from biological, corrosion product, and external sources) aging effects where applicable in system components exposed to a raw water environment.

Corporate and station procedures provide instructions and controls for preventive actions through raw water chemistry control (chemical and biocide injection), performance monitoring through station testing, and condition-monitoring and leak detection through inspection and testing of TMI-1 raw water systems in the scope of license renewal. The TMI-1 Inservice Pressure Testing Program provides for periodic leakage detection of aboveground and buried piping and components as well as inspection of aboveground piping and components.

OCCWS AMP testing and inspections at TMI-1 have detected buildup of deposit and loss of material aging effects in raw water system components prior to loss of system intended functions. GL 89-13 program assessments have been performed, and corrective actions have been implemented.

For heat exchangers, an aging management program that uses multiple attributes is considered necessary to effectively address all aging effects. These AMP activities provide input into a total program that includes primary and secondary operating fluid chemistry controls, performance monitoring and inspections of all heat exchangers in the scope of license renewal at TMI-1 to manage loss of material, and buildup of deposit where applicable.

NUREG-1801 Consistency

The Open-Cycle Cooling Water System aging management program is consistent with the ten elements of aging management program XI.M20, Open-Cycle Cooling Water System, specified in NUREG-1801 with the following exceptions:

Exceptions to NUREG-1801

NUREG-1801 program scope consists of preventive measures to mitigate the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms. The TMI-1 Open-Cycle Cooling Water System aging management program will also be used to manage the following aging effects and mechanisms for the internal surfaces of concrete circulating water piping:

- Cracking and expansion due to reaction with aggregates
- Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack
- Increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide

The TMI-1 Open-Cycle Cooling Water System aging management program activities are adequate for managing the aging effects of the internal surfaces of concrete circulating water piping.

Enhancements

A new river water chemical treatment system will be installed to treat the river water systems for biofouling, including microbiologically-influenced (MIC) corrosion.

Operating Experience

Significant microbiologically-influenced corrosion (MIC), failure of protective coatings, and fouling have been observed in a number of heat exchangers. The guidance of NRC GL 89-13 has been implemented for approximately 10 years and has been effective in managing aging effects due to biofouling, corrosion, erosion, protective coating failures, and silting in structures and components serviced by OCCW systems. Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, and fouling, reduction of heat transfer due to fouling, cracking and expansion due to reaction with aggregates, cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel, increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack, increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide are being adequately managed.

The following examples of operating experience provide objective evidence that the Open-Cycle Cooling Water System program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. In November 2001, routine eddy current testing was performed on the 1B intermediate closed cooling water heat exchanger. The test results identified indications in 10 of the 369 tubes inspected. The indications ranged from 21% to 50% through-wall with two indications greater than 45% though-wall. After further NDE was performed, the two tubes with the larger indication were plugged to reduce risk of possible leakage during the next operating cycle. Since there were no through-wall leaks, the degraded condition of the tubes had no impact on plant operation during the previous cycle.

   An apparent cause evaluation was performed to determine the cause of the tube degradation. Review of maintenance history for the heat exchanger showed that 8 of the 10 tubes with indications were newly installed during the previous refueling outage. The early degradation of the tubes indicated the presence of a rapid pitting mechanism inside the heat exchanger. The evaluation concluded that the most significant mode of degradation was under-deposit corrosion, based the identification of silt in lower half of the heat exchanger. MIC or MIC-related ammonia-induced cracking was considered a contributing mode of degradation, as seasonal ammonia is present in the river. This operating experience example provides objective evidence that a) routine testing and NDE is effective at identifying degradation in cooling water systems in a timely manner; b) OCCW system deficiencies are evaluated and corrective actions are properly implemented to maintain system intended functions, and; c) deficiencies associated with OCCW inspection and activities are documented in the corrective action process.

2. In June 2002, a thru wall leak was identified in the 30-inch circulating water pipe upstream of valve CW-V-13C. The leak size was estimated to be approximately 1 gpm. Indications on the top surface of the pipe suggested microbiologically influenced corrosion (MIC) was the likely cause of the leak. Technical evaluation of the condition concluded that the flaw did not jeopardize the capabilities of the circulating water system. The system provides cooling water to the main condenser and the feedwater pump turbine condensers. Evaluation of the leak took into consideration the effects of other leaks previously identified in this system. Due to orientation and location of the leak, there was no impact on nearby equipment including valve motor operators. An extent of condition review identified other action items addressing repair of piping upstream of valves CW-V-13C and CW-V-13D. Repairs were completed in the T1R15 outage. This operating experience provides objective evidence that a) a history of MIC exists at TMI-1; b) flaws caused by

MIC are identified and properly evaluated for impact on plant operation, and; c) that repairs are scheduled and performed in a timely manner.

3. In December 2005, a microbiologically-influenced corrosion, (MIC) leak was discovered in the Nuclear River – Secondary River cross connect line. The leak was in a carbon steel pipe in a low flow area. UT was performed on the leak area a few weeks after it was discovered, and results showed acceptable wall thickness except at the location of the leak. Per the ASME code case, UT examinations are required every 90 days until the leak is repaired. Subsequent UT examinations showed no further degradation beyond the original failure. The piping where the leak occurred was replaced during the outage in the fall of 2007. This operating experience provides objective evidence that a) flaws caused by MIC are identified and properly evaluated for impact on plant operation, b) deficiencies associated with OCCW inspection and activities are documented in the corrective action process, and; c) that repairs are scheduled and performed in a timely manner.

Problems identified in the operating experience of the Open-Cycle Cooling Water System program would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Open-Cycle Cooling Water System program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the Open-Cycle Cooling Water System program are performed to identify the areas that need improvement to maintain the quality performance of the program.

Conclusion

The enhanced Open-Cycle Cooling Water System program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.10 CLOSED-CYCLE COOLING WATER SYSTEM

Program Description

The Closed-Cycle Cooling Water System aging management program is an existing program that provides for managing aging of piping, piping components, piping elements and heat exchangers that are included in the scope of license renewal for loss of material and reduction of heat transfer and are exposed to a closed cooling water environment at TMI-1. The program provides for preventive, performance monitoring and condition monitoring activities that are implemented through station procedures. Preventive activities include measures to maintain water purity and the addition of corrosion inhibitors to minimize corrosion based on EPRI 1007820.

Performance monitoring provides indications of degradation in closed-cycle cooling water systems, with plant operating conditions providing indications of degradation in normally operating systems. In addition, station maintenance inspections and nondestructive examination (NDE) provide condition monitoring of heat exchangers exposed to closed-cycle cooling water environments.

NUREG-1801 Consistency

The Closed Cycle Cooling Water System aging management program is consistent with the ten elements of aging management program XI.M21, Closed Cycle Cooling Water System, specified in NUREG-1801 with the following exception:

Exceptions to NUREG-1801

NUREG-1801 refers to EPRI TR-107396 1997 Revision. TMI-1 implements the guidance provided in EPRI 1007820, which is the 2004 Revision to TR-107396. EPRI periodically updates industry water chemistry guidelines, as new information becomes available. TMI-1 has reviewed EPRI 1007820 and has determined that the most significant difference is that the new revision provides more prescriptive guidance and has a more conservative monitoring approach. EPRI 1007820 meets the same requirements of EPRI TR-107396 for maintaining conditions to minimize corrosion and microbiological growth in closed cooling water systems for effectively mitigating many aging effects.

Enhancements

A one-time inspection of selected components in stagnant flow areas will be conducted to confirm the absence of aging effects resulting from exposure to closed cycle cooling water. Also, a one-time inspection of selected CCCW chemical mix tanks and associated piping components will be performed to verify corrosion has not occurred on the interior surfaces of the tanks and associated piping components.

Operating Experience

Degradation of closed-cycle cooling water systems due to corrosion product buildup or through-wall cracks in supply lines has been observed in operating plants. Accordingly, operating experience demonstrates the need for this program. Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that cracking due to stress corrosion cracking, loss of material due to general, pitting, crevice, and galvanic corrosion, and reduction of heat transfer due to fouling are being adequately managed. The following examples of operating experience provide objective evidence that the Closed-Cycle Cooling Water System program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. In February 2003, molybdate fell below the minimum limit during a system flush of the Decay Heat Closed Cooling Water (DHCCW) system. A chemistry recommendation was written to add molybdate to keep the system concentration above the limit. A follow up sample after the addition showed the molybdate to be above the minimum level.

   The molybdate concentration fell below the specification value during a system flush to reduce chloride below the chloride goal concentration. A planned flush was scheduled to decrease the chloride concentration of the system below the goal value. The flush was planned well before the specification concentration for chlorides was reached. This type of flush is needed periodically because the biocides used contribute to the chloride concentration in the system and the chloride builds up after multiple biocide additions. A chemistry recommendation to make a proactive addition of molybdate was generated to minimize out of spec hours that might be encountered when the flushing process started. In addition, an increased monitoring frequency was established to ensure that out of specification hours would be minimized during the flushing process. The molybdate concentration dropped below the minimum value for a short period of time during the flushing process (i.e. nine hours). An evaluation showed that the carbon steel was protected during the nine-hour period of time. In addition, there is no indication that any protective coatings on the system were at risk while the system was brought back into the desired band. In other words, the system was protected during the flush and actions taken to minimize the out of specification hours reduced risk of corrosion during the flush. This operating experience example provides objective evidence that a) routine sampling and chemical analysis of the cooling water is effective at identifying off normal chemistry parameters in a timely manner; b) CCCW chemistry monitoring activity deficiencies are evaluated and corrective actions are properly implemented to maintain system intended functions, and; c) deficiencies associated with CCCW chemistry monitoring activities are documented in the corrective action process.

2. In early 2002, the closed cooling water (CCCW) chemistry program was converted to nitrite-free treatment to reduce the risk of nitrites being converted to ammonia by microbiological activity. At that time, all CCCW subsystems had biological activity associated with residual sludge. After program conversion, the subsystems ammonia levels were frequently monitored until nitrites were no longer detected in process water. Ion chromatography testing replaced a specific ion electrode testing method to improve testing accuracy. Eventually, ammonia was no longer detected in CCCW subsystems either by TMI plant chemistry or by vendor testing.

   However, in December 2002, routine water chemistry monitoring identified a high chloride concentration in the closed cooling water subsystems. The ammonia level exceeded the plant administrative goal of 2.0 ppm for closed cooling water for the first time since 1995. Immediate corrective actions included testing to confirm proper copper corrosion inhibitor concentrations and issuing recommendations to flush the three affected subsystems to reduce ammonia concentrations. Additionally, a detailed system review was performed to determine if any connecting or interfacing plant systems could add ammonia to the closed cooling water subsystems. The review showed that no interfacing systems or components were sources of ammonia. The ion chromatography analytical procedure was also reviewed and tested for accuracy correctness. Samples of the two biocides routinely added to the subsystems were mixed at normal treatment concentration and tested for ammonia using ion chromatography procedure. Both products tested positive for ammonia. Each showed concentrations of ammonia similar to those measured in the three affected subsystems. Corrective actions included reducing ammonia levels in the CCCW subsystems to normal levels and improving the product evaluation and procurement procedures used for the purchase of new treatment chemicals.

   This operating experience example provides objective evidence that a) CCCW chemical monitoring processes are upgraded to improve effectiveness; b) routine sampling and chemical analysis of the cooling water is effective at identifying off normal chemistry parameters in a timely manner. c) CCCW chemistry monitoring activity deficiencies are evaluated and corrective actions are properly implemented to maintain system intended functions, and d) deficiencies associated with CCCW chemistry monitoring activities are documented in the corrective action process.

3. In May 2002, weekly chemistry analysis of closed cooling systems resulted in pH levels in three closed cooling systems below the specification limit. Chemistry recommendations were initiated to add sodium hydroxide to increase pH values over the next two days. Follow-up testing showed the pH returned to acceptable levels. This operating experience example provides objective evidence that routine sampling and chemical analysis of the cooling water is

effective at identifying off normal chemistry parameters in a timely manner.

TMI-1 has had no instances of closed-cycle cooling water system chemistry sample results out of specification since 2003.

The operating experience of the Closed-Cycle Cooling Water System program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Closed-Cycle Cooling Water System program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the Closed-Cycle Cooling Water System program are performed to identify the areas that need improvement to maintain the quality performance of the program.

Conclusion

The enhanced Closed-Cycle Cooling Water System aging management program will provide reasonable assurance that loss of material, cracking, and fouling aging effects are adequately managed so that the intended functions of components exposed to closed-cycle cooling water environments within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.11 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

Program Description

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program is an existing program that provides for periodic visual inspections of cranes and hoists in the scope of 10 CFR 54.4. The program includes structural components that make up the bridge, the trolley, the rail system, structural bolting, and lifting devices, and includes cranes and hoists that meet the provisions of NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants.”

The aging management program is implemented through station procedures that are based on ASME/ANSI B30.2, B30.16 and rely upon visual inspection to manage loss of material. Structural bolting is monitored for loss of preload by inspecting for loose or missing bolts, or nuts. Inspection frequency is annually for cranes and hoists that are accessible during plant operation and every 2 years for cranes and hoists that are only accessible during refueling outages.

The program will be enhanced to include visual inspection of rails in the rail system for loss of material due to wear, and visual inspection of structural bolting for loss of material due to corrosion. Acceptance criteria will be enhanced to require significant loss of material due to wear or corrosion be evaluated or corrected to ensure the intended function of the crane or hoist is not impacted. The enhancements will be implemented prior to entering the period of extended operation.

NUREG-1801 Consistency

With enhancements, the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program is consistent with the ten elements of aging management program XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems," specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

- The program will be enhanced to require visual inspection of the rails in the rail system for loss of material due to wear.
- The program will be enhanced to require visual inspection of structural bolts for loss of material due to general corrosion.
- Acceptance criteria will be enhanced to require evaluation of significant loss of material due to wear of the rail in the rail system.

Operating Experience

1. In 1997, Wolf Creek discovered polar crane rail clamping plate studs broken. The failures were randomly distributed around the perimeter of the rail and attributed to fatigue. Wolf Creek identified similar failures in 1992 on the polar crane and the turbine building crane. Evaluation by Wolf Creek determined that failure of 5 studs out of 840 studs did not impact the intended function of crane. Inspections conducted on the TMI-1 polar crane rail system have not identified broken clamping plate studs.

2. In 1995, Trojan Nuclear Plant identified a failed section of reactor building crane rail. Visual, metallographic examination and evaluation of the condition by the licensee concluded that failure was preexisting and was caused by inappropriate use of cutting torch during construction. This operating experience was reported in NRC Information Notice (IN) 96-26, Recent Problems with Overhead Cranes. TMI-1 review of IN 96-26 concluded that no action is required because the problem is attributed to original construction.

3. In 1999, Whiting Corp. issued a 10 CFR Part 21 Notice for the reactor building polar crane. Whiting determined that the main hoist drum-bearing pedestal at the gear end of the drum and the trolley top flange weld in the area of the pedestal might be overstressed. Whiting recommends a visual and of the pedestal truck weld and top trolley plate web welds for cracks. If cracks or indications are detected Whiting recommended a repair.

   In response to the 10 CFR Part 21 Notice, TMI-1 conducted visual examination of the welds as recommended by Whiting. The welds were found to be representative of good workmanship without evidence of any distress, cracking, or distortion, and the weld size result showed that it is in excess of the manufacturer's analyzed weld size.

4. A review of approximately 400 TMI-1 corrective action reports (IRs) did not identify history of loss of material due to corrosion in cranes in hoists structural members or loss of material due to wear in the rail system. The IRs were generated to document issues related to active components, procedure noncompliance such as missed inspection frequency, and personnel safety issues. Issue Report No.00181799 was issued to document loose bolts and cracked welds found during the 2003 biannual inspection of the reactor building polar crane as described below.

5. During inspection of the polar crane bridge rail support system (diagonal bracing), bolts were found loose and one support was found to have a cracked weld. This condition was found by visual examination during the periodic inspection of the crane in accordance with procedure R2009396. Additional inspections

revealed cracked welds on 4 other pairs of braces for a total of 5 out of 16 pairs of diagonal braces. Engineering investigation for the cause of the loose bolts determined that the condition of the bolts was not due to age related degradation. The bolts were purposely installed loose per design requirements to accommodate thermal expansion of the girder. The cause of the identified cracked welds was not found in the reviewed documentation. However engineering evaluation documented in ECR 03-00872 concluded that the cracked welds in 5 of the 16 lateral braces do not impact the intended function of the polar crane. The polar crane inspection implementing procedure was revised to require visual examination of the welds in each of the 16 lateral (diagonal) braces for new cracks and crack growth each time the crane is inspected in the future.

Conclusion

The enhanced Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program will provide reasonable assurance that loss of material and loss of preload aging effects are adequately managed so that the intended functions of cranes and hoists structural components within the scope of license renewal are maintained consistent with current licensing basis (CLB) during the period of extended operation.

B.2.1.12 COMPRESSED AIR MONITORING

Program Description

The Compressed Air Monitoring aging management program is an existing program that provides for managing the internal surface aging effects of loss of material due to general, pitting and crevice corrosion, and the reduction of heat transfer due to fouling for piping and components in a compressed air system. The TMI-1 aging management activities consist of preventive and condition-monitoring measures to manage the aging effects.

NUREG-1801 Consistency

The TMI-1 Compressed Air Monitoring aging management program is an existing program that is consistent with NUREG-1801 aging management program XI.M24, Compressed Air Monitoring program.

Exceptions to NUREG-1801

None.

Enhancements

The Compressed Air Monitoring program will be enhanced to include instrument air system air quality testing for dew point, particulates, lubricant content, and contaminants to ensure that the contamination standards of ANSI/ISA-S7.0.01-1996, paragraph 5 are met. These enhancements will be made to the existing program GL 88-14 Instrument Air Program.

In addition the Compressed Air Monitoring program will be enhanced to include air sampling activities on a representative sampling of headers on a yearly basis in accordance with ASME OM-S/G-1998, Part 17 and EPRI TR-108147.

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

Operating Experience

Industry operating experience indicates that internal degradation can cause significant degradation to susceptible plant components. The following examples of operating experience provide objective evidence that the Compressed Air Monitoring program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation

1. Examples of leakage in the TMI instrument air system were reported in a number of TMI Issue Reports (IR s) initiated from April 2002 to October 2003. Plant personnel found this leakage during the conduct of plant activities not directly associated with instrument air system activities. Examples such as these support the fact that plant personnel are aware of the impact to plant equipment from

instrument air leakage and they are routinely identifying leaks. In order to close these IRs the leaks are repaired and if appropriate root cause analysis is performed to minimize reoccurrences.

2. Performance of the air dryers is actively monitored and maintained within acceptance criteria as evidenced by reports initiated between April and June 2004. Operators are continuously monitoring dew point as a part of rounds. When the instrument air quality is not within acceptance limits, corrective actions are immediately taken to resolve the condition.

3. Air quality tests were conducted on other air systems such as Service Air in June 2006. The results of these air quality tests were analyzed for content, reviewed by the system manager and entered into the corrective action process as appropriate. The corrective action process includes an evaluation of these conditions for applicability to other air systems and through this process recommendations are identified that improve instrument air quality in other plant air systems.

Conclusion

The enhanced Compressed Air Monitoring aging management program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.13 FIRE PROTECTION

Program Description

The Fire Protection program is an existing program that provides for aging management of various fire protection related components within the scope of License Renewal.

The program provides for visual inspections of fire barrier penetration seals for signs of degradation, such as change in material properties, cracking, and hardening, through periodic inspection, surveillance and maintenance activities. The program provides for visual inspection of fire barrier walls, ceilings and floors in structures within the scope of license renewal for the aging effects of cracking, and loss of material. Periodic visual inspections of fire doors are performed for signs of degradation such as holes in skin, wear, or missing parts. Fire door clearances are checked during periodic inspections and when fire doors and components are repaired or replaced. Additionally, periodic functional tests of fire doors are performed. The program will provide for managing loss of material aging effects for the fuel oil lines for the TMI-1 diesel-driven fire pumps by the performance of periodic surveillance tests. The program will provide for aging management of external surfaces of the TMI-1 carbon dioxide and halon fire suppression system components through periodic operability tests and visual inspections for corrosion and mechanical damage. These inspections and tests are implemented through station procedures and recurring task work orders.

NUREG-1801 Consistency

The Fire Protection program is consistent with the ten elements of aging management program XI.M26, "Fire Protection," specified in NUREG- 1801 with the following exception:

Exceptions to NUREG-1801

NUREG-1801 recommends visual inspection and functional testing of the halon and CO2 fire suppression systems at least once every six months. Procedurally, the TMI-1 halon fire suppression system currently undergoes operational testing and inspections every 18 months, and the TMI-1 low-pressure carbon dioxide fire suppression system undergoes operational testing and inspections every 24 months. Additionally, the halon fire suppression system undergoes more frequent visual inspections for system charge (storage tank pressure at least every 3 months, and storage tank weight at least every 6 months), and the low-pressure carbon dioxide fire suppression system undergoes a visual storage tank level and pressure check at least weekly. These test frequencies are considered sufficient to ensure system availability and operability based on the station’s operating history that shows no aging related events that have adversely affected system operation.

Similar exceptions to the NUREG-1801 recommended frequency for periodic function test of the halon and CO2 fire suppression systems were previously approved by the NRC in NUREG-1796, Safety Evaluation Report Related to the License Renewal of the Dresden Nuclear Power Station, Units 2 and 3 and Quad Cities Nuclear Power Station, Units 1 and 2, and in NUREG-1875, Safety Evaluation Report Related to the License Renewal of Oyster Creek Generating Station. In each case for these plants, periodic functional testing of the halon and CO2 fire suppression systems is currently performed every 18 months. (Additionally, for Dresden and Quad Cities, the Technical Requirements Manual permits a testing frequency of once every two years.) The NRC staff found that on the basis of plant experience, the testing frequency was adequate for aging management considerations. For these plants, as for TMI-1, station operating history indicated that there were no occurrences of aging related events having adversely affected system operation.

A review of the functional surveillance tests performed for the TMI-1 halon and CO2 systems within the last five years confirmed that there have been no occurrences of aging related events that adversely affected either system's operation.

The December 2006 halon system functional test was completed with all steps satisfactory after an evaluation of a repeated switch actuation required for multiple fan start determined that the switch had not been manually operated properly for the test. No occurrence of any aging related degradation having adversely affected the system's operation was observed. The June 2005 halon system functional was completed with all steps satisfactory. No occurrence of any aging related degradation having adversely affected the system's operation was observed. During the February 2004 halon system functional test, a fan motor failed and required replacement, and a valve limit switch required adjustment to properly indicate the associated valve was fully open. No occurrence of any aging related degradation of passive components having adversely affected the system's operation was observed.

The November 2005 CO2 system functional test was completed with all steps satisfactory. Although an evaluation determined that a damaged fire damper grill was redundant and did not require replacement, the primary grill for the damper is functional for foreign material exclusion and the damper and system are operable. No occurrence of any degradation of passive components due to aging having adversely affected the system's operation was observed. During the November 2003 CO2 system functional test, an electro-thermal link did not fully melt, causing a damper to not fully close. The link was replaced and the test re-performed satisfactorily. A CO2 tank level was found low due to performance of a test and was subsequently re-filled. No occurrence of any aging related degradation having adversely affected the system's operation was observed. The October 2001 CO2 system functional test was competed with all steps satisfactory. No occurrence of any aging related degradation having adversely affected the system's operation was observed.

On the basis of TMI-1 plant experience that no occurrence of any aging related degradation having adversely affected either the halon or the CO2 systems' operation has been observed, the test frequencies are considered sufficient to ensure system availability and operability, and are adequate for aging management considerations.

Enhancements

The Fire Protection program will be enhanced as follows:

1. The program will provide for additional inspection criteria for degradation of fire barrier walls, ceilings, and floors

2. The program will provide specific fuel supply line inspection criteria for diesel-driven fire pumps during tests

Enhancements will be implemented prior to the period of extended operation.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that concrete cracking and spalling due to freeze-thaw, aggressive chemical attack, and reaction with aggregates; loss of material due to corrosion of embedded steel, wear, general, pitting, crevice corrosion, and other means; change in material properties due to various degradation mechanisms; cracking due to various degradation mechanisms; and hardening and loss of strength due to elastomer degradation are being adequately managed. The following examples of operating experience provide objective evidence that the Fire Protection program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. During a fire penetration seal inspection in accordance with procedures in 2006, a seal in the floor of the control room was found degraded. This seal exhibited foam shrinkage, and the RTV sealant applied as a binder between the foam and the curb during seal installation was less than adequate to last the life of the seal. A fire watch was established, the seal was scheduled for repair and the condition corrected. A determination was made to examine all remaining seals of similar size, configuration and environment, and the subject seal was the only one to exhibit the shrinkage problem. This example provides objective evidence that operating experience regarding foam seal failures is considered when establishing inspection criteria, that foam shrinkage will be detected during walkdown examinations, and that compensatory actions as directed by procedure (fire watch) are enacted.

2. During a Triennial Fire Inspection walkdown in 2002, inspectors noted that fasteners were missing from metal plate closures that connect the metal-clad fire-rated wall to the concrete fire-rated wall in the control building, in some instances causing gaps. An evaluation determined that the operability of the fire barriers and

walls was not affected since the gaps were bounded by clearance criteria for rated fire doors, and also because redundant plates on the opposing sides of the wall were intact. The missing fasteners were installed, all similar installations were inspected, and the inspection procedures were revised to direct inspection for similar construction discrepancies. This example provides objective evidence that discrepancies are documented in the corrective action process, and that the program is updated as necessary to ensure that it remains effective in identifying conditions for evaluation and repair in order to maintain component intended functions.

3. A daily surveillance in 2002 identified a degraded condition of a fire door sill plate. Anchors attaching the sill plate were sheared such that the plate was mislocated, causing a gap in excess of allowable acceptance criteria. Per the Fire Protection program, a time clock was initiated and compensatory measures were taken. An evaluation determined a cart or other device passing through the doorway damaged the sill plate. The door was replaced with a new door that achieved required clearance gaps without use of a sill plate, so that the problem would not reoccur. This example provides objective evidence that discrepancies are documented in the corrective action process, that compensatory measures are taken per the program, and that evaluations and repair are performed in order to maintain component intended functions.

4. In 2005, an evaluation of repeated fire door latch failures requiring compensatory fire watches determined that the commercially designed locksets were failing due to severe usage conditions. The evaluation determined that a heavy-duty model designed for institutional service was more appropriate for the high cycling and differential pressure conditions experienced by the subject fire doors. The locksets were replaced resulting in more reliable service. This example provides objective evidence that the program's surveillance activities identify degradations, that degradations are entered into the corrective action process, and that evaluations and repair are performed in order to maintain component intended functions.

5. A review of TMI-1 operating experience has shown no reports of loss of function of the diesel-driven fire pumps as a result of corrosion or degradation of the fuel oil system.

6. In 2005, surveillance identified that a halon system solenoid valve located in the air intake tunnel stuck open after a test actuation. An evaluation determined that the valve, while showing some discoloration due to corrosion, was operable and fully capable of actuating when required to suppress a fire in the air intake tunnel. It was determined that the harsh environment of the air intake tunnel, and the valve's inaccessibility in the event of a fire in the tunnel, warranted a proactive replacement of the valve, along with the other similar valves also located in the air intake tunnel. This example

provides objective evidence that the program's surveillance activities identify degradations, that degradations are entered into the corrective action process, and that evaluations and repair are performed in order to maintain component intended functions.

In October 2002 and December 2005, two NRC-conducted triennial fire protection inspections were performed at TMI-1. The objective of these inspections was to assess whether TMI-1 has implemented an adequate fire protection program and that post-fire safe shutdown capabilities have been established and are being properly maintained. A total of only three findings were cited (two in 2002 and one in 2005), each with a classification of very low safety significance and treated as a non-cited violation.

Conclusion

The enhanced Fire Protection program covers various fire protection related components within the scope of license renewal including fire barrier doors, walls, ceilings, floors, and penetration seals. It also covers external surfaces of the halon and carbon dioxide fire suppression system components. In addition, the program covers the fuel oil systems for the diesel-driven fire pumps. The enhanced Fire Protection aging management program will provide reasonable assurance that the aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.14 FIRE WATER SYSTEM

Program Description

The Fire Water System program is an existing program that will manage identified aging effects for the water-based fire protection system and associated components, through the use of periodic inspections, monitoring, and performance testing. The program provides for preventive measures and inspection activities to detect aging effects prior to loss of intended functions. System functional tests, flow tests, flushes and inspections are performed in accordance with guidance from NFPA standards. Fire system main header flow tests are conducted at least once every three years. Hydrant flushing and inspections are conducted at least once every twelve months. The condition of the fire pumps is confirmed once every 18 months by performance of a pump functional test. The Fire Service Head (Altitude) Tank is inspected internally once every 5 years. Sprinkler system inspections are performed at least once every refueling outage. The fire water system is maintained at the required normal operating pressure and monitored such that a loss of system pressure is immediately detected and corrective actions initiated. The system flow testing, visual inspections and volumetric inspections assure that the aging effects of loss of material due to corrosion, microbiologically influenced corrosion (MIC), or biofouling are managed such that the system intended functions are maintained.

NUREG-1801 Consistency

The Fire Water System aging management program is consistent with the ten elements of aging management program XI.M27, "Fire Water System," specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

The Fire Water System program will be enhanced to include:

1. Periodic non-intrusive wall thickness measurements of selected portions of the fire water system at intervals that do not exceed every 10 years.

2. Sampling of sprinklers in accordance with NFPA 25, “Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” and submitting the samples to a testing laboratory prior to the sprinklers being in service 50 years. Subsequent testing is at intervals that do not exceed every 10 years.

Enhancements will be implemented prior to the period of extended operation, except sprinkler head inspections that will begin prior to sprinklers being in service 50 years.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that the loss of material due to general, pitting, crevice and microbiologically influenced corrosion, and fouling are being adequately managed. The following examples of operating experience provide objective evidence that the Fire Water System program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. Following a test run and shut down of the diesel-driven river fire pump in 2005, fire service system pressure lowered until the motor-driven river fire pump auto-started on low fire service header pressure. An investigation indicated an underground piping leak that was successfully isolated and scheduled for repair. The cause of the leak was determined to be environmental mechanical damage (rock bearing on the underground pipe) and subsequently repaired. This example provides objective evidence that detected degradation is entered into the corrective action process for evaluation and repair prior to loss of intended function, and that the corrective action process effectively determines the cause of the degradation.

2. During performance of fire protection system operations surveillance in 2005, a leak was identified on a threaded elbow. The leak was quantified, evaluated for cause (MIC), and determined to not impact FSAR-described or Technical Specification functions, and to not be reportable. The condition was subsequently repaired. This example provides objective evidence that the program provides for detection of degradation, that degradation is entered into the corrective action process for evaluation and repair prior to loss of intended function, and that the corrective action process effectively determines the cause of the degradation.

3. During performance of a TMI Fire Safe Shutdown Self-Assessment in 2002, a single pendant sprinkler head in the Engineered Safeguards Actuation Systems (ESAS) room was found not to be listed or approved for use in a dry pipe system application. The condition was evaluated and determined to be acceptable, and was identified for documentation as a code deviation. The condition evaluation found that while the head was installed per design in order to direct water away from potential obstructions, subsequent conversion of the system from a wet pipe to a dry pipe system to avoid the possibility of inadvertent actuation did not evaluate acceptability of this one sprinkler head for use in a dry system. The installation was determined to be acceptable, and a code deviation was documented. This example provides objective evidence that deficiencies discovered during periodic self-assessments performed in accordance with the program are entered into the corrective action process for evaluation and repair. It also demonstrates that the corrective action process effectively evaluates and dispositions deficiencies prior to any loss of intended function.

4. In 2007, a fire service valve previously closed to isolate an underground leak could not be opened due to valve operator resistance. An evaluation was performed which determined that multiple alternate flow paths existed such that operability of the fire system was not adversely affected. A flow test confirmed that required fire service flow was available to all areas of the plant at flow rates consistent with previous tests. The valve was subsequently replaced. This example provides objective evidence that detected degradation is entered into the corrective action process for evaluation and repair prior to any loss of intended system function.

In October 2002 and December 2005, two NRC-conducted triennial fire protection inspections were performed at TMI-1. The objective of these inspections was to assess whether TMI-1 has implemented an adequate fire protection program and that post-fire safe shutdown capabilities have been established and are being properly maintained. A total of only three findings were cited (two in 2002 and one in 2005), each with a classification of very low safety significance and treated as a non-cited violation.

Conclusion

The enhanced Fire Water System aging management program will provide reasonable assurance that the aging effects are adequately managed so that the intended functions of fire water system components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.15 ABOVEGROUND STEEL TANKS

Program Description

The Aboveground Steel Tanks aging management program is an existing program that will provide for management of loss of material aging effects for outdoor carbon steel tanks. The program credits the application of paint as a corrosion preventive measure and performs periodic visual inspections to monitor degradation of the paint and any resulting metal degradation for the carbon steel tanks. One-time internal UT inspections will be performed on the bottom of the Condensate Storage Tanks, which are supported by concrete foundations. The Fire Service Head Tank (Altitude Tank) and Sodium Hydroxide Tank are not directly supported by an earthen or concrete foundation and will undergo external visual inspections without the necessity of bottom surface UT inspections.

The Condensate Storage Tanks are supported by concrete foundations and have sealant at the tank-foundation interfaces which will be periodically inspected for degradation. The Altitude Tank and Sodium Hydroxide Tank are raised tanks not directly supported by earthen or concrete foundations, and inspection of the sealant at the tank-foundation interface does not apply.

The Aboveground Steel Tanks aging management program is an existing program. Enhancements will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Aboveground Steel Tanks aging management program is consistent with the ten elements of aging management program XI.M29, Aboveground Steel Tanks, specified in NUREG-1801 with the following exception:

Exceptions to NUREG-1801

NUREG-1801 states that periodic plant system walkdowns each outage are used to monitor degradation. The TMI-1 program utilizes tank inspections at least every five years in place of periodic system walkdowns each outage. Tank components subject to outdoor air are constructed from carbon steel. The carbon steel tanks are protected by a protective coating. Industry guidance and experience indicate that monitoring of exterior surfaces of components made of this material and protective coating on a frequency of at least every five years provides reasonable assurance that loss of material will be detected before an intended function is affected.

Enhancements

The existing TMI-1 Aboveground Steel Tanks program implementing procedures will be enhanced to include one-time thickness measurements of the bottom of the Condensate Storage Tanks, which are supported on concrete foundations. Measurements will be taken to ensure that significant degradation is not occurring and the component intended function will be maintained during the extended period of operation.

The program will also be enhanced to inspect the condition of the sealant between CSTs and the concrete foundations.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that aging effects/mechanisms are being adequately managed. Coating degradation, such as flaking and peeling, has occurred in safety-related systems and structures. Corrosion damage near the concrete-metal interface and sand-metal interface has been reported in metal containments. Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that loss of material due to general, pitting, and crevice corrosion is being adequately managed. The following examples of operating experience provide objective evidence that the Aboveground Steel Tanks program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. In 2005, the annual external inspection of the Fire Service Head tank discovered minor blistering and chipped paint. The condition, which was discovered prior to tank degradation (i.e., no rust or leaks), was entered into the TMI-1 Corrective Action Process. Although the tank had been repainted four years earlier, this was the first time this condition had been noted on the painted surfaces. The condition was evaluated and a predictive maintenance action tracking item was created to monitor and trend the condition.

2. In 2007, the annual external inspection of the Fire Service Head tank did not identify any new conditions. No evidence of leaks or structural damage was noted. Insulation was removed during the previous annual inspection and not entirely replaced. The repair of the insulation was entered into the Corrective Action Process.

3. In 2007, the five-year external inspection of the Sodium Hydroxide Tank found no discrepancies with regard to the tank inspection criteria. This operating experience shows that there are no aging effects on the external surface of this tank, and the condition of the tank external surface will support the tank intended functions.

Conclusion

The enhanced Aboveground Steel Tanks aging management program will provide reasonable assurance that the aging effects of loss of material are adequately managed so that the intended functions of outdoor aboveground tanks within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation. Enhancements will be implemented prior to the period of extended operation.

B.2.1.16 FUEL OIL CHEMISTRY

Program Description

The Fuel Oil Chemistry aging management program is an existing program that includes preventive activities to provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of Licensing Renewal. The fuel oil tanks within the scope of the program are maintained by monitoring and controlling fuel oil contaminants in accordance with the guidelines of the American Society for Testing and Materials (ASTM). Fuel oil sampling activities meet the requirements of ASTM D 4057-95 (2000), or, provide a more conservative sample for the detection of contaminants and water and sediment. Fuel oil will be periodically sampled and analyzed for particulate in accordance with modified ASTM Standard D 2276-00 Method A and for the presence of water and sediment in accordance with ASTM Standard D 1796-97. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel and stored fuel. Fuel oil tanks are periodically drained of accumulated water and sediment and periodically drained, cleaned, and internally inspected. These activities effectively manage the effects of aging by providing reasonable assurance that potentially harmful contaminants are maintained at low concentrations.

NUREG-1801 Consistency

The Fuel Oil Chemistry aging management program is consistent with the ten elements of aging management program XI.M30, "Fuel Oil Chemistry," specified in NUREG-1801 with the following exceptions:

Exceptions to NUREG-1801

- NUREG-1801 states in XI.M30 that the fuel oil aging management program is focused on managing the conditions that cause general, pitting, and microbiologically influenced corrosion (MIC). The TMI-1 aging mechanisms in fuel oil also include the loss of material due to crevice corrosion and biological fouling. The contaminants that cause crevice corrosion and biological fouling are similar to those that cause general, pitting and microbiologically influenced corrosion (MIC). Therefore, the monitoring and inspection techniques used to manage the conditions that cause general, pitting, and microbiologically influenced corrosion (MIC) will be effective in managing the loss of material due to crevice corrosion and biological fouling.
- NUREG-1801 states in XI.M30 that the fuel oil aging management program is in part based on the fuel oil purity and testing requirements of the plant's Technical Specifications that are based on the Standard Technical Specifications of NUREG-1430 through NUREG-1433. TMI-1 has not adopted the Standard Technical Specifications as described in these NUREGs; however, the TMI-1 fuel oil specifications and procedures invoke equivalent requirements for fuel oil purity and fuel oil testing as described by the Standard Technical Specifications.

- NUREG-1801 states that the program serves to reduce the potential of exposure of the tank internal surface to fuel oil contaminated with water and biological organisms. This is accomplished by analyzing multilevel samples for water and sediment, biological activity, and particulate on a periodic basis (at least quarterly). Fuel oil tanks should also be periodically drained of accumulated water and sediment, and, periodically drained, cleaned, and internally inspected. The following are exceptions to these requirements:
    - Multilevel sampling, tank bottom draining, cleaning, and internal inspection of the 7.3 gallon Station Blackout Diesel Clean Fuel Tank is not periodically performed at TMI-1. This tank is integral to the routine operation of the Station Blackout Diesel and collects excess clean fuel oil from the diesel engine that has been previously analyzed within its managed source tank, the Station Blackout Diesel Fuel Storage Tank. The Clean Fuel Tank is small in size and experiences a turnover of the fuel collected within as a result of routine engine operation. Therefore, the periodic draining of water and sediment from the bottom of the Clean Fuel Tank, and, the periodic draining, cleaning, and internal inspections are not necessary. To confirm the absence of any significant aging effects, a one-time inspection of the Station Blackout Diesel Clean Fuel Tank will be performed as part of the TMI-1 Fuel Oil Chemistry aging management program. Should the one-time inspection reveal evidence of aging effects, this condition will be entered into the corrective action process for resolution.
    - Multilevel sampling, tank bottom draining, cleaning, and internal inspection of the 550 gallon Station Blackout Diesel Fuel Day Tank is not periodically performed at TMI-1. This tank is integral to the routine operation of the Station Blackout Diesel and is filled with fuel oil that has been previously analyzed within its managed source tank, the Station Blackout Diesel Fuel Storage Tank. The fuel oil within the Day Tank is recirculated to the Station Blackout Diesel Fuel Storage Tank quarterly to prevent the accumulation of contaminants and water and sediment. Therefore, the periodic draining of water and sediment from the bottom of the Day Tank, and, the periodic draining, cleaning, and internal inspections are not necessary. To confirm the absence of any significant aging effects, a one-time inspection of the Station Blackout Diesel Day Tank will be performed as part of the TMI-1 Fuel Oil Chemistry aging management program. Should the one-time inspection reveal evidence of aging effects, this condition will be entered into the corrective action process for resolution.
- NUREG-1801 requires periodic multilevel sampling of tanks in accordance with the manual sampling standards of ASTM D 4057-95 (2000). TMI-1 has not committed to ASTM D 4057-95 (2000) for manual sampling standards:
    - The Diesel Fire Pump 350 gallon fuel oil storage tank and the Emergency Diesel Generator 550 gallon fuel oil day tank samples are single point samples obtained from the tank drain line located off of the bottom of the tank. This sample is not considered a multilevel sample as described in ASTM D 4057. Although the actual sample location is a

single point taken from the tank bottom, the lower sample elevation is more likely to contain contaminants and water and sediment which tend to settle in the tank, thus making this a conservative and effective sampling location for fuel oil contaminants. Operating experience from January 2000 through June 2007 has shown that this sample method has yielded consistently acceptable sample results.

- The 50,000 gallon fuel oil storage tank samples are obtained from an in-line sample connection located off of the tank outlet piping. This sample is not considered a multilevel sample as described in ASTM D 4057. Sampling of the tank is performed after recirculating the tank contents which promotes tank mixing and purging of the recirculation and sample piping. Although the actual sample draw off location is off of the tank outlet which is towards the bottom of the tank, the lower sample elevation is more likely to contain contaminants and water and sediment which tend to settle in the tank, thus making this a conservative and effective sampling location for fuel oil contaminants. Operating experience from January 2005 through July 2007 has shown that this sample method has yielded consistently acceptable sample results.

Enhancements

The TMI-1 Fuel Oil Chemistry aging management program will be enhanced to include:

- The completion of full spectrum fuel oil analysis within 31 days following the addition of new fuel oil into fuel storage tanks.
- The determination of water and sediment in accordance with ASTM D1796-97.
- The analysis for particulate contamination in new and stored fuel oil in accordance with modified ASTM D2276, Method A.
- The analysis for bacteria in new and stored fuel oil.
- The addition of biocides, stabilizers, or corrosion inhibitors as determined by fuel oil analysis activities.
- Activities to periodically drain, clean, and inspect the 50,000 gallon fuel oil storage tank, the 550 gallon diesel generator day tanks, the 25,000 gallon station blackout diesel fuel storage tank, and the Diesel Fire Pump 350 gallon fuel oil storage tanks.
- Activities to periodically drain water and sediment from tank bottoms for the 50,000 gallon fuel oil storage tank, the 30,000 gallon diesel generator fuel storage tank, and the Diesel Fire Pump 350 gallon fuel oil storage tanks.
- The analysis of new oil for specific or API gravity, kinematic viscosity, and water and sediment prior to filling the 50,000 gallon fuel oil storage tank and the Diesel Fire Pump 350 gallon fuel oil storage tanks.
- Quarterly sampling for the 550 gallon diesel generator day tanks.
- Sampling of new fuel oil deliveries in accordance with ASTM D 4057-95 (2000).

- Multilevel sampling of the Emergency Diesel Generator 30,000 gallon fuel oil storage tank and the SBO Diesel Generator 25,000 gallon fuel oil storage tank in accordance with ASTM D 4057.
- The use of ultrasonic techniques for determining tank bottom thicknesses should there be any evidence of loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, and fouling found during visual inspection activities.

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

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, and fouling are being adequately managed. The following examples of operating experience provide objective evidence that the Fuel Oil Chemistry aging management program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. In January 2005, a review of the quarterly diesel fuel oil samples taken from the fire service pump diesel fuel oil tank indicated an increasing trend for total insolubles. Following consultation with the fuel oil vendor, it was determined that the total insoluble contaminant increase was caused by oxidation of the fuel (aging). The usability of the fuel oil was evaluated and determined acceptable in the short term. In order to return the fuel oil to within specification in order to maintain the long-term health of the fuel storage tank, the fuel oil was drained, the tank flushed, and new fuel oil added. Following these activities, sampling was performed which verified the effectiveness of this corrective action. Additional corrective actions included re-evaluation and improvements to TMI-1 monitoring activities for all site fuel oil storage tanks. This example provides objective evidence that a) fuel oil monitoring activities identify fuel oil contaminants that can lead to aging effects, b) deficiencies found during fuel oil monitoring activities are documented in the corrective action process, and c) fuel oil monitoring activity deficiencies are evaluated and corrective actions implemented to maintain system intended functions.

2. In January 2004, the TMI-1 fuel oil sampling program was reviewed against standard Exelon fuel oil sampling practices and the improved Technical Specifications in use at Limerick and Peach Bottom. As a result of this review, improvements were made to the sampling activities including changes to sampling frequencies, sampling techniques, and tested parameters. Preventative actions to preclude the accumulation of water and sediment were also incorporated into the site fuel oil monitoring activities. This example provides objective evidence that a) assessments are performed proactively to identify potential program improvements, b)

improvements identified during assessments are captured in the corrective action process, and c) improvements are evaluated and implemented as required to enhance program effectiveness.

3. In October 2005, fuel oil sample analysis from the fire diesel fuel oil tank indicated an elevated level of total insolubles. Confirmatory testing was performed on this tank for total insolubles with satisfactory results. As a result of this discrepancy, sample reports for 2005 were reviewed to identify total insoluble trends. Based on this review, it was concluded that the results of the October 2005 sample were inaccurate, or, the sample was contaminated. This example provides objective evidence that a) fuel oil monitoring activities identify fuel oil contaminants that can lead to aging effects, b) deficiencies found during fuel oil monitoring activities are documented in the corrective action process, and c) fuel oil monitoring activity deficiencies are evaluated and corrective actions implemented to maintain system intended functions.

4. The 50,000 gallon fuel oil storage tank samples are obtained from an in-line sample connection located off of the tank outlet piping. This sample is not considered a multilevel sample as described in ASTM D 4057. Sampling of the tank is performed after recirculating the tank contents which promotes tank mixing and purging of the recirculation and sample piping. Operating experience from January 2005 through July 2007 has shown that this sample method has yielded consistently acceptable sample results.

5. The Diesel Fire Pump 350 gallon fuel oil storage tank and Emergency Diesel Generator 550 gallon fuel oil day tank samples are single point samples obtained from the tank drain line located off of the bottom of the tank. This sample is not considered a multilevel sample as described in ASTM D 4057. Operating experience from January 2000 through June 2007 has shown that this sample method has yielded consistently acceptable sample results.

The operating experience of the Fuel Oil Chemistry aging management program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Fuel Oil Chemistry aging management program will effectively identify degradation prior to failure.

Conclusion

The enhanced TMI-1 Fuel Oil Chemistry aging management program will provide reasonable assurance that the loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, and fouling will be adequately managed so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation.

B.2.1.17 REACTOR VESSEL SURVEILLANCE

Program Description

The TMI-1 Reactor Vessel Surveillance program is an existing program that manages the reduction of fracture toughness of the reactor vessel beltline materials due to neutron embrittlement. The program fulfills the intent and scope of 10 CFR 50, Appendix H. The program provides for evaluation of neutron embrittlement by projecting upper-shelf energy (USE) for all reactor materials with projected neutron exposure greater than 10^{17} n/cm2 (E >1MeV) during 60 years of operation and with the development of pressure-temperature limit curves. Embrittlement information is obtained in accordance with RG 1.99, Rev. 2 chemistry tables.

TMI-1 participates in the Pressurized Water Reactor Owners Group (PWROG) Master Integrated Reactor Vessel Surveillance Program (MIRVSP), which monitors TMI-1 reactor vessel beltline materials that are projected to exceed a cumulative neutron fluence of 10^{17} n/cm2 (E >1MeV) during 60 years of service. The MIRVSP includes all seven operating B&W 177-fuel assembly (FA) plants and six participating Westinghouse-designed plants having B&W-fabricated reactor vessels. The purpose of the MIRSVP is to augment the existing Reactor Vessel Surveillance Programs for the participating units and to provide a basis for sharing information between plants. The integrated program is feasible because of the similarity of the design and operating characteristics of the affected plants, as required by 10 CFR Part 50, Appendix H, paragraph II.C. The integrated program provides sufficient material data to meet the ASTM E-185-82 capsule program requirement for monitoring embrittlement.

The program consists of two parts – the first is the plant-specific program, which is the continued irradiation of the surveillance capsules transferred from those reactors in which the capsule holder tubes were damaged to host reactors with intact upgraded capsule holders. The TMI-1 capsules were placed in the Crystal River-3 reactor for irradiation. Those that have been irradiated and tested fulfill the ASTM E-185-82 Capsule Program Requirement for TMI-1. The second part of the program is made up of special research capsules designed to provide fracture toughness data on Linde 80 weld metals predicted to exhibit high sensitivity to irradiation damage. The irradiation schedules for the MIRVSP include the plant-specific capsules, supplementary weld metal surveillance capsules and higher fluence supplementary weld metal surveillance capsules for the Linde 80 materials. The capsule withdrawal schedule for limiting Linde 80 weld metal heats will result in neutron fluence exposures corresponding to 60 and 80 years of operation.

The program manages the steps taken if reactor vessel exposure conditions are altered; such as the review and updating of 60-year fluence projections to support the preparation of new pressurized shock reference temperature calculations, Charpy upper shelf energy calculations and pressure-temperature limit curves.

TMI-1 does not have surveillance capsules remaining inside the reactor vessel, but uses ex-vessel cavity dosimetry to monitor neutron fluence. The cavity dosimetry program was developed and implemented to make it possible to continuously monitor the neutron fluence on each reactor vessel, as described in NRC-approved topical report BAW-1875-A. This will continue during the period of extended operation as part of the aging management program for reactor vessel neutron embrittlement.

NUREG-1801 Consistency

The TMI-1 Reactor Vessel Surveillance program is an existing program that is consistent with NUREG-1801 aging management program XI.M31, Reactor Vessel Surveillance.

Exceptions to NUREG-1801

None.

Enhancements

The TMI-1 Reactor Vessel Surveillance program will be enhanced to address maintenance of the TMI-1 cavity dosimetry exchange schedule. The program will also be enhanced to clarify that, if future plant operations exceed the limitations or bounds specified in Regulatory Position 1.3 of RG 1.99, Rev. 2, the impact of plant operation changes on the extent of reactor vessel embrittlement will be evaluated and the NRC will be notified. Enhancements will be implemented prior to the period of extended operation.

Operating Experience

1. The integrated reactor vessel material surveillance program was designed when the surveillance capsule holder tubes in a number of B&W reactors were damaged and could not be repaired without a complex and expensive repair program and considerable radiation exposure to personnel. For these plants, including TMI-1, the original Reactor Vessel Surveillance Program could not provide sufficient material data and dosimetry to monitor embrittlement; therefore, the integrated program was developed. The purpose of the MIRSVP is to augment the existing Reactor Vessel Surveillance Programs for the participating units and to provide a basis for sharing information between plants. The integrated program is feasible because of the similarity of the design and operating characteristics of the affected plants, as required by 10 CFR Part 50, Appendix H, paragraph II.C. The integrated program provides sufficient material data to meet the ASTM E-185-82 capsule program requirement for monitoring embrittlement.

2. The NRC staff evaluated the basis for the integrated program concept, determined the MIRVSP to be acceptable, and approved TR BAW-1543 (NP), Revision 3, by letter dated June 11, 1991. This letter concluded that the program met the applicable criteria from 10

CFR 50, Appendix H, “Reactor Vessel Material Surveillance Program Requirements.”

3. TR BAW-1543 (NP), Revision 4, issued in February 1993, updated some of the units’ withdrawal schedules. TR BAW-1543 (NP), Revision 4, Supplement 1 reflected revised fluence values for some units and revised some withdrawal schedules to comply with the 1973 Edition of American Society for Testing and Materials (ASTM) Standard E 185, “Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels” (ASTM E 185-73). It was anticipated that future updates to TR BAW-1543 (NP) would only involve changes to the Revision 4 Supplement. Supplement 2, issued in June 1996, reflected revised fluence values and the revised withdrawal schedules. Supplement 3, issued in February 1999, deleted Rancho Seco, R. E. Ginna, and Zion, Units 1 and 2, from the program. In addition, it updated the capsule status and the peak end-of-license fluences for several plants. Supplement 4, issued in May 2002, incorporated the disposal plan for stored capsules, updated the status for various capsules, and incorporated current fluence levels.

4. Supplement 5 was issued in December 2003 because the previous supplement included a commitment regarding Capsules OC1-D and OC3-F; however, that commitment could not be met because these capsules could not be removed from Crystal River, Unit 3. The NRC staff approved the revised withdrawal schedules for Oconee, Units 1, 2, and 3, and Three Mile Island, Unit 1 (TMI-1), in Supplement 5-A in May 2005. The NRC staff found that each of these plants met the capsule withdrawal schedule requirements of the 1982 Edition of ASTM Standard E185 (ASTM E 185-82), even though the original capsules were not going to be withdrawn and tested for Oconee, Units 2 and 3, and TMI-1, because there were other capsules within the MIRVSP that contained the same limiting material for the subject plants that would be withdrawn and tested and, therefore, would satisfy the requirements of ASTM Standard E185-82.

5. Supplement 6 was submitted in December 2005 to provide updates to fluence values and to the surveillance capsule insertion and withdrawal schedules. The NRC issued Draft Safety Evaluation Report for Supplement 6 in May 2007 for comment, and in it indicated that the revised capsule insertion and withdrawal schedules are acceptable. Therefore, the MIRVSP continues to meet the requirements of 10 CFR 50, Appendix H and the capsule withdrawal schedule requirements of ASTM E-185-82.

The operating experience of the Reactor Vessel Surveillance Program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. Periodic self-assessments of the program are performed to identify the areas that need improvement to maintain the quality performance of the program.

Conclusion

The enhanced TMI-1 Reactor Vessel Surveillance aging management program will provide sufficient material data and dosimetry to meet the ASTM E-185-82 capsule program requirement for monitoring embrittlement of the TMI-1 reactor vessel. The continued implementation of the enhanced TMI-1 Reactor Vessel Surveillance aging management program will provide reasonable assurance that neutron irradiation embrittlement will be adequately managed so that the intended functions of the reactor vessel will be maintained during the period of extended operation.

B.2.1.18 ONE-TIME INSPECTION

Program Description

The TMI-1 One-Time Inspection aging management program is a new program that will provide reasonable assurance that an aging effect is not occurring, or that the aging effect is occurring slowly enough to not affect a components intended function during the period of extended operation, and therefore will not require additional aging management. The program will be credited for cases where either (a) an aging effect is not expected to occur but there is insufficient data to completely rule it out, (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected, or (c) the characteristics of the aging effect include a long incubation period.

The One-Time Inspection program will be used for the following:

- To confirm the effectiveness of the Water Chemistry program to manage the loss of material, cracking, and the reduction of heat transfer aging effects for steel, stainless steel, copper alloy, nickel alloy, and aluminum alloy in treated water, steam, and reactor coolant environments.
- To confirm the effectiveness of the Fuel Oil Chemistry program to manage the loss of material aging effect for steel, stainless steel, and copper alloy in a fuel oil environment.
- To confirm the effectiveness of the Lubricating Oil Analysis program to manage the loss of material and the reduction of heat transfer aging effects for steel, stainless steel, copper alloy, and aluminum alloy in a lubricating oil environment.
- To confirm the loss of material aging effect is insignificant for stainless steel and copper alloy in an air/gas – wetted environment.

The new program elements include (a) determination of the sample size based on an assessment of materials of fabrication, environment, plausible aging effects/mechanisms, and operating experience; (b) identification of the inspection locations in the system or component based on the aging effect; (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) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the period of extended operation. When evidence of an aging effect is revealed by a one-time inspection, the engineering evaluation of the inspection results would identify appropriate corrective actions.

The inspection sample includes “worse case” one-time inspection of more susceptible materials in potentially more aggressive environments (e.g., low or stagnant flow areas) to manage the effects of aging. Examination methods will include visual examination, VT-1 or VT-3, or equivalent, as appropriate, or volumetric examinations. Acceptance criteria are in accordance with industry guidelines, codes, and standards.

The One-Time Inspection aging management program will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The One-Time Inspection aging management program is consistent with the ten elements of aging management program XI.M32, “One-Time Inspection,” specified in NUREG-1801 with the following exception:

Exceptions to NUREG-1801

NUREG-1801 specifies in XI.M32 the 2001 ASME Section XI B&PV Code, including the 2002 and 2003 Addenda for Subsections IWB, IWC, and IWD. The TMI-1 ISI Program Plan for the third ten-year inspection interval effective from April 20, 2001 through April 19, 2011, approved per 10 CFR 50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for TMI-1 will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval.

Enhancements

None.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that aging effects/mechanisms are being adequately managed. The One-Time Inspection program applies to potential aging effects for which there are currently no operating experience indicating the need for an aging management program. Nevertheless, the elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice. Specific Operating Experience and objective evidence does exist for attributes in which this program covers, such as the effectiveness of NDE techniques at identifying, confirming, and/or quantifying aging effects. The following examples of operating experience provide objective evidence that NDE is effective in assuring that intended function(s) would be maintained consistent with the CLB for the period of extended operation. These examples also demonstrate how the corrective action process is used to document and evaluate unacceptable NDE results.

1. In October 2004, while performing UT pipe thickness inspections, it was discovered that the wall thickness was below the nominal manufacturing tolerance of 87%. Engineering performed a review for operability and concluded that the as-found wall thickness exceeded the minimum wall thickness required by the B31.1 Code. Engineering also concluded that based on the maximum predicted corrosion rate, the minimum wall thickness required by the B31.1

Code would not be exceeded for several fuel cycles. Based on remaining life, engineering recommended future re-inspection to ensure a conservative design margin prior to reaching predicted failure. This example provides objective evidence that a) the NDE program identifies aging effects prior to the loss of intended function, b) deficiencies found during NDE are documented and evaluated for impact on system operability and intended functions, and c) follow-up inspections are specified when necessary to confirm remaining design margin assumptions.

2. In November 2005, while performing UT pipe thickness inspections on ¾" pipe, it was discovered that the wall thickness had been reduced. Engineering performed a review for operability and concluded that the as-found wall thickness provided a safety factor of 10 and an adequate corrosion margin until the next refueling outage, at which time the thinned piping would be replaced. This example provides objective evidence that a) the NDE program identifies aging effects prior to the loss of intended function, b) deficiencies found during NDE are documented and evaluated for impact on system operability and intended functions, and c) replacement activities are specified when necessary to maintain system intended functions.

3. In November 2001, while performing scheduled augmented ISI visual (VT-1) examinations, cracking was discovered on the High Pressure Injection/Makeup nozzle thermal sleeve. Engineering performed a review for operability and concluded that it was "highly improbable" that the identified crack in the thermal sleeve would propagate such that a significant loose part (e.g., inboard end of the thermal sleeve) would be generated during the next 24-month fuel cycle. The evaluation also concluded that in the unlikely event that the end of the thermal sleeve was lost early in the fuel cycle the loose part would not cause any structural or operational problems. Additionally, the effects on the nozzle of operating for a full fuel cycle without the end of the thermal sleeve were evaluated and were shown to be within code requirements. This example provides objective evidence that a) the NDE program identifies aging effects prior to the loss of intended function and b) deficiencies found during NDE are documented and evaluated for impact on system operability and intended functions.

Conclusion

The new One-Time Inspection program will provide reasonable assurance that either an aging effect is not occurring, or the aging effect is occurring so slowly that the intended function of the component or structure consistent with the current licensing basis is not affected. In either case there would be no need to manage an aging related degradation for the period of extended operation.

B.2.1.19 SELECTIVE LEACHING OF MATERIALS

Program Description

The Selective Leaching of Materials aging management program is a new program that will consist of one-time inspections to determine if loss of material due to selective leaching is occurring. The scope of the program will include components made of susceptible materials and located in potentially aggressive environments. Susceptible materials at TMI-1 are gray cast iron, copper alloy with greater than 15% zinc. Envrionments include raw water, closed cooling water, treated water, and soil.

The Selective Leaching of Materials aging management program will be implemented prior to the period of extended operation. The program will provide for visual inspections, hardness tests, and other appropriate examinations, as required, to identify and confirm existence of the loss of material due to selective leaching. If degradation is found, the condition of affected components will evaluated to determine the impact on their ability to perform intended functions during the period of extended operation. Condition monitoring and expanded sampling will be utilized, as required, to ensure the components perform as designed.

NUREG-1801 Consistency

The Selective Leaching of Materials aging management program is consistent with NUREG-1801 Section XI.M33, Selective Leaching of Materials.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Selective Leaching of Materials aging management program is new. Therefore, no programmatic operating experience is currently available. However, the review of TMI-1 operating experience identified the dezincification of copper alloys containing greater than 15% zinc in treated water environments. Specifically, in December 2004, dezincification occurred in a tubing cap of a test tee for a pressure gauge in the main steam system. This condition contributed to the failure of the tubing cap. The failed tubing cap was replaced with a stainless steel cap. Subsequently, the tubing cap on the test tee for a companion gage was inspected. No markings indicating material grade could be identified, therefore this cap was also replaced with one made of austenitic steel in accordance with the plant design. A preliminary extent-of-condition walkdown was conducted on similar test connections in the immediate area of the failed test cap. Included were components of the main steam and emergency feedwater systems. No other discrepancies were identified.

Conclusion

The new Selective Leaching of Materials aging management program inspections will provide reasonable assurance that loss of material aging effects due to selective leaching are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.20 BURIED PIPING AND TANKS INSPECTION

Program Description

The Buried Piping and Tanks Inspection aging management program is an existing program that includes preventive measures to mitigate corrosion and periodic inspection of external surfaces for loss of material to manage the effects of corrosion on the pressure-retaining capacity of piping and components in a soil (external) environment. Preventive measures are in accordance with standard industry practices for maintaining external coatings and wrappings.

External inspections of buried components will occur opportunistically when they are excavated during maintenance. Inspection of buried cast iron, carbon steel, concrete-coated steel, and stainless steel piping and components will have been performed in the ten years prior to the period of extended operation. Upon entering the period of extended operation, a focused inspection of an example of each of the above materials shall be performed within ten years, unless an opportunistic inspection occurs within this ten-year period. There have been several yard excavation activities to date that have uncovered buried piping and components and inspections of the buried piping and components. A cast iron fire protection component was excavated in 2005 and carbon steel condensate piping was excavated in 2006. During the 2007 outage, the concrete coated carbon steel Secondary River Water piping was excavated. Therefore, inspections of buried cast iron, carbon steel, and concrete-coated carbon steel piping or components have occurred in the ten years prior to the period of extended operation. Inspections will be performed on at least one stainless steel pipe or component prior to the period of extended operation. Inspection of the buried Diesel Generator Fuel Storage 30,000 Gallon Tank both within the ten-year period prior to the period of extended operation, and within ten years of entering the period of extended operation will be performed as described below.

The program will be enhanced as described below to provide reasonable assurance that buried piping and components will perform their intended function during the period of extended operation.

NUREG-1801 Consistency

The Buried Piping and Tanks Inspection aging management program is consistent with the ten elements of aging management program XI.M34, "Buried Piping and Tanks Inspection," specified in NUREG-1801 with the following exceptions:

Exceptions to NUREG-1801

- NUREG-1801, Section XI.M34 Buried Piping and Tanks Inspection aging management program scope only includes buried steel piping and components. However TMI-1 also includes stainless steel in their buried piping program that will be managed as part of this aging management program.

- NUREG-1801, Section XI.M34 Buried Piping and Tanks Inspection aging management program relies on preventive measures such as coatings and wrappings. However portions of buried stainless steel piping may not be coated or wrapped. Inspections of buried piping that is not wrapped will inspect for loss of material due to general, pitting, crevice, and microbiologically influenced corrosion.
- NUREG-1801, Section XI.M34 Buried Piping and Tanks Inspection aging management program recommends that opportunistic or focused inspections of the external surfaces of buried components be performed. Internal inspection and UT of the buried Diesel Generator Fuel Storage 30,000 Gallon Tank wall will be used in lieu of inspection of the external surface of this tank. This internal surface visual inspection and UT examination of the tank wall will provide an alternate means to monitor the tank's pressure retaining ability.

Enhancements

The Buried Piping and Tanks Inspection aging management program will be enhanced to include at least one opportunistic or focused excavation and inspection of stainless steel piping and components prior to entering the period of extended operation. (Inspection activities of buried piping and components for cast iron, carbon steel, and concrete-coated carbon steel materials have occurred in the ten years prior to the beginning of the period of extended operation.) Upon entering the period of extended operation, a focused inspection of an example of each of the above materials shall be performed within ten years, unless an opportunistic inspection occurs within this ten-year period.

An internal inspection and UT of the buried Diesel Generator Fuel Storage 30,000 Gallon Tank wall will be used in lieu of inspection of the external surface of this tank. This inspection will be performed within the ten-year period prior to the period of extended operation, and within ten years of entering the period of extended operation.

Operating Experience

Operating experience shows that the program described here is effective in managing corrosion of external surfaces of buried steel piping and tanks. However, because the inspection frequency is plant-specific and depends on the plant operating experience, the applicant's plant-specific operating experience is further evaluated for the extended period of operation. Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that loss of material due to general, pitting, crevice, and microbiologically influenced corrosion are being adequately managed. The following examples of operating experience provide objective evidence that the Buried Piping and Tanks Inspection program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. In August 2005, a water leak on a fire service piping valve was discovered. During required packing repair, the nearby piping was exposed during the excavation. The piping was inspected and found the external coating was in good condition, as was the interior of the piping.

2. In December 2006, a fire service valve was replaced. During the replacement, coatings were removed and re-applied where the freeze seal had been applied for valve replacement. Following completion of the work, it was discovered that the coating application steps did not include the appropriate inspection testing. The coating procedures and specifications were revised to include appropriate inspection testing. There was no indication that the as-found coating was degraded.

3. In June 2006, it was determined that a leak occurred in the Condensate Storage Tank (CST) “A” de-ice line between the Turbine Building and CST “A”. When the piping was excavated, the coating was deteriorated and corrosion was present on the outside surface of the piping. The piping was cut out and replaced. The cause of the failure was the use of improper backfill material around the piping, which resulted in ballast-type rock contacting and damaging the outer pipe coating. This resulted in the localized corrosion which eventually led to a through-wall leak. Other underground piping locations were selected and excavated. In each case, the correct backfill material had been present. A comprehensive underground piping inspection program was developed, considering location, design, protection, coating, consequences of failure and type of inspections to be performed. In April 2007, an underground leak in the same piping line was detected. Investigation determined that this leak developed in a mechanical joint (flange), which was inadvertently damaged during the earlier repair. The leak was repaired in June 2007, and the underground piping line was subsequently redesigned and replaced. This example provides objective evidence that deficiencies in the program are identified and entered into the corrective action process and that the program is updated as necessary to ensure that it remains effective for condition monitoring of piping and components within the scope of license renewal.

The operating experience of the Buried Piping and Tanks Inspection program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Buried Piping and Tanks Inspection program, as enhanced for license renewal, will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the Buried Piping and Tanks Inspection program are performed to identify the areas that need improvement to maintain the quality performance of the program.

Conclusion

The enhanced Buried Piping and Tanks Inspection aging management program will provide reasonable assurance that the aging effects on the external surfaces of buried piping and components are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.21 EXTERNAL SURFACES MONITORING

Program Description

The External Surfaces Monitoring aging management program is a new program that directs visual inspections that are performed during system walkdowns. The program consists of periodic visual inspection of components such as piping, piping components, ducting, and other components within the scope of license renewal. The program provides for management of aging effects through visual inspection of external surfaces for evidence hardening and loss of strength and loss of material. Visual inspections may be augmented by physical manipulation to detect hardening and loss of strength of elastomers. Loss of material due to boric acid corrosion is managed by the Boric Acid Corrosion program. The external surfaces of components that are buried and those of above ground tanks are inspected via the Buried Piping and Tanks Inspection program and the Aboveground Steel Tanks program, respectively. This program does not provide for managing aging of internal surfaces.

NUREG-1801 Consistency

The TMI-1 External Surfaces Monitoring aging management program is a new program that is consistent with NUREG-1801 aging management program XI.M36, External Surfaces Monitoring with the following exceptions.

Exceptions to NUREG-1801

The NUREG-1801 aging management program XI.M36, External Surfaces Monitoring program is based on system inspections and walkdowns. This program consists of periodic visual inspections of steel components such as piping, piping components, ducting, and other components within the scope of license renewal and subject to AMR in order to manage aging effects. The program manages aging effects through visual inspection of external surfaces for evidence of material loss. Exceptions to NUREG-1801 are:

- An increase to the scope of the materials inspected (i.e., aluminum alloy, asbestos cloth, copper alloy, elastomers, and stainless steel)
- An increase to the scope of aging effects (i.e., hardening and loss of strength).

Enhancements

None.

Operating Experience

Corrosion of external surfaces, particularly steel components where paint damage has exposed bare metal, can result in significant material degradation if left unnoticed.

1. During the December 2004 system walkdown, engineering noticed an uncoated/painted Circulating Water System valve. Similar valves are painted to prevent external corrosion of the valve and valve operator. The valve was painted to prevent external corrosion.

2. In February 2006, the Control Building Chiller was found to have minor surface corrosion on the condenser shell. The areas of the chiller that were found to have corrosion were cleaned and repainted to prevent further degradation.

3. The Altitude Tank fill check valve was found to be rusting during a June 2005 walkdown. The corrosion was due to condensation forming on the external surfaces of the fill line and aging paint. Corrective action was taken to clean and repaint the valve to prevent further degradation.

Conclusion

The new External Surfaces Monitoring aging management program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of structures and components within the scope license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.22 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

Program Description

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new program that provides for managing cracking due to stress corrosion cracking; hardening and loss of strength due to elastomer degradation; loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, cracking, and fouling; and reduction of heat transfer due to fouling. The program includes provisions for visual inspections of the internal surfaces and volumetric testing of components not managed under any other aging management program and initiate corrective action. The program also includes inspection of the external surfaces of expansion joints in ducting.

NUREG-1801 Consistency

The TMI-1 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new program that is consistent with NUREG-1801 aging management program XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components with the following exceptions.

Exceptions to NUREG-1801

The NUREG-1801 aging management program XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components consists of inspections of the internal surfaces of steel piping, piping components, ducting, and other components that are not covered by other aging management programs. These internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. The program includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. Exceptions to NUREG-1801 are:

- An increase of the component material types within the scope of this program (i.e., asbestos, copper alloy with 15% zinc or more, copper alloy with less than 15% zinc, neoprene, nickel alloy, rubber, stainless steel, and titanium alloy).
- An increase of the aging effects within the scope of this program (i.e., cracking, reduction of heat transfer, and hardening and loss of strength).
- Volumetric testing will be used to detect SCC of stainless steel components
- Physical manipulation may be used to detect hardening and loss of strength of elastomers both internally and externally.

Enhancements

None.

Operating Experience

Industry operating experience indicates that internal degradation can cause significant degradation to susceptible plant components. Existing plant procedures that direct visual inspections of internal surfaces of piping and ducting have identified minimal instances of internal degradation. Continued implementation of these procedures plus a new procedure to expand the systems and components inspected will be adequate to manage degradation during the period of extended operation. Examples of degradation identified by these procedures include:

1. Every refueling outage Engineering performs an internal inspection of the Reactor Building Cooling Units upstream of the normal cooling coils, down stream of the emergency coils, and the fan inlets and fan outlets. During the 2003 outage, samples of boric acid were taken from the bottom section of the inlet of each normal cooling coil bank. Boron deposits coating less than 5% of the total surface area of the normal cooling coils were found. Generally, the Reactor Building Cooling Units have less than 5% surface area fouling overall. There was an increase in the amount of boron deposition since the last refueling outage visual inspection, but it was expected due to an ongoing reactor coolant leak rate. The consequence of the boron fouling of the Reactor Building Recirculation Fan & Coolers is a reduction in heat transfer. The fans and coolers were cleaned of the boron deposits in accordance with the Corrective Action Process. The reactor coolant leak has since been fixed.

2. In 2005, leak testing of the Auxiliary Boiler Sump identified leakage from the Blowdown Tank drain line to the sump. Boroscope inspection of the drain line identified corrosion in the horizontal run. Operation of the boilers requires use of the blowdown tank and associated drain line. Repair to the blowdown tank drain was needed to prevent further release of water from the Condensate System. The drain line was repaired in accordance with the Corrective Action Program.

3. During a 2004 visual inspection of internal surfaces of Condensate Storage Tank A, damaged coatings and corrosion was discovered in the inner diameter of a drain line. A technical evaluation concluded excessive corrosion in the localized degraded coating area would not occur prior to recoating in 2009.

Conclusion

The new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of structures and components within the scope license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.23 LUBRICATING OIL ANALYSIS

Program Description

The TMI-1 Lubricating Oil Analysis aging management program is an existing program that provides oil condition monitoring activities to manage the loss of material and the reduction of heat transfer in piping, piping components, piping elements, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. Sampling and condition monitoring activities identify specific wear products, contamination and the physical properties of lubricating oil within operating machinery to ensure that intended functions are maintained.

NUREG-1801 Consistency

The Lubricating Oil Analysis aging management program is consistent with the ten elements of aging management program XI.M39, “Lubricating Oil Analysis Program,” specified in NUREG-1801 with the following exception:

Exceptions to NUREG-1801

NUREG-1801 recommends that flash point be determined for lubricating oil. Flash point will not be measured for all lubricating oil in service. The determination of flash point in lubricating oil is used to indicate the presence of highly volatile or flammable materials in a relatively nonvolatile or nonflammable material, such as found with fuel contamination in lubricating oil. The TMI-1 oil analysis guidelines only include the measurement of flash point for diesel engine lubricating oil where there is the potential for the contamination of lubricating oil with fuel. Flash point is not measured for other lubricating oils where there is no potential for the contamination of lubricating oil with fuel. For all lubricating oils, flash point is used as a quality control measurement when receiving new oil. Flash point is not a primary measurement to determine the presence of water or contaminants in lubricating oil, which are the environmental parameters necessary for the loss of material and reduction of heat transfer aging effects.

Enhancements

None.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that aging effects/mechanisms are being adequately managed. The following examples of operating experience provide objective evidence that the Lubricating Oil Analysis aging management program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. Analysis and review of the monthly oil sample data in January 2004 for the main turbine oil reservoir and feedwater pump/turbine oil reservoirs indicated an increasing particle count. A large sudden injection of particles into the systems from abnormal bearing wear, mechanical shock to the system, or failure of the bowser filter units was considered. This failure mode would drive the particle count extremely high in a short period of time. The trend of particle increase since January of 2003 was a slow, steady trend with the exception of June. Based on this continued trend, the theory of a large injection into the turbine oil system was rejected. A review of the other physical properties of the oil: viscosity, TAN and Spectrochemical analysis was performed and it was concluded that this data did not support abnormal bearing wear. Review of the vibration monitoring system data also concluded no bearing degradation issues.

   Confirmatory sampling activities were performed in order to determine bowser filter efficiency. As a result if this testing, it was concluded that the bowser filter units required replacement, even though differential pressure thresholds for filter replacement were not exceeded. Additional reviews of the sample results on the main oil reservoir revealed evidence of variances in cleanliness with the suspected cause being technique. To eliminate these sampling variances, a new sample point was installed to achieve consistent sample results. This example provides objective evidence that a) lubricating oil monitoring activities identify lubricating oil contaminants that can lead to aging effects, b) deficiencies found during lubricating oil monitoring activities are documented in the corrective action process, and c) lubricating oil monitoring activity deficiencies are evaluated and corrective actions implemented to maintain system intended functions.

2. A Self-Assessment of the Emergency Diesel Generator crankcase lubricating oil program was performed by corporate engineering in September 2005. The program was assessed against Exelon procedures and the applicable Owner’s Group recommendations for Fairbanks Morse Emergency Diesel Generators. The overall conclusion was that the Emergency Diesel Generator lubricating oil program is being executed in a generally satisfactory manner. Several program deficiencies were noted at TMI. One of these deficiencies was attributed to a known oil contamination issue (see OE item below). A deficiency in magnesium level was identified that had not been previously identified by the plant staff. This was entered into the corrective action process for evaluation and determination of root cause. The third deficiency identified was associated with inadequate sampling techniques and was also entered into the corrective action process. This example provides objective evidence that a) assessments are performed to verify the effectiveness of program execution, b) deficiencies found during assessments are documented in the corrective action process, and

c) assessment deficiencies are evaluated and corrective actions implemented to maintain program effectiveness.

3. Contaminated lubricating oil has remained in TMI ‘A’ Emergency Diesel Generator since 1999. In April 1999, 10 gallons of the wrong lubricating oil was accidentally introduced into the engine sump due to an operator error. This oil has a different additive package than the lubricating oil normally used at TMI. Review of the oil analysis reports showed that this error has caused persistently high levels of zinc in the engine oil, which is normally a sign of oil contamination. Review of the corrective action evaluation, which dispositioned the issue, provided no technical basis for the long-term acceptability of this condition. This deficiency was identified during a September 2005 corporate “Check-In” assessment of the Emergency Diesel Generator crankcase lubricating oil program (see OE item above) and entered into the corrective action process. The follow-up evaluation of this condition concluded that the elevated zinc level was not a result of contamination; it was inherent to the lubricating oil inadvertently added in 1999. Additionally, it was also concluded that there were no wear parts of the diesel engine in contact with the oil that would contribute to the elevated zinc concentrations. As an interim corrective action, revised alert/fault values were established based on the elevated zinc levels in accordance with the guidance specified for zinc for Emergency Diesel Generator lubricating oil. The zinc values obtained during routine oil analysis activities following implementation of the increased alert/fault guidelines did not exceed the alert/fault values established.

   Zinc concentration above the reference value did not affect the function of the engine as evidenced by major inspections conducted in April 2006. No adverse findings were identified during this inspection. A complete lubricating oil change was performed as a final disposition to this issue. This example provides objective evidence that a) deficiencies found during lubricating oil monitoring activities are documented in the corrective action process, and b) lubricating oil monitoring activity deficiencies are evaluated and corrective actions implemented to maintain system intended functions.

The operating experience of the Lubricating Oil Analysis aging management program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Lubricating Oil Analysis aging management program will effectively identify degradation prior to failure.

Conclusion

The Lubricating Oil Analysis aging management program provides reasonable assurance that the loss of material and the reduction of heat transfer aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.24 ASME SECTION XI, SUBSECTION IWE

Program Description

The ASME Section XI, Subsection IWE aging management program provides for inspection of Reactor Building liner plate, including its integral attachments, penetration sleeves, pressure retaining bolting, personnel airlock and equipment hatch, seals, gaskets, and moisture barrier, and other pressure retaining components. It is implemented through procedures that implement ASME Section XI, Subsection IWE requirements for detecting loss of material (general, pitting, and crevice corrosion), loss of pressure retaining bolting preload, cracking due to cyclic loading, loss of sealing, leakage through containment/deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants).

TMI-1 has completed ASME Section XI Subsection IWE General Visual Examinations for the first and the second periods of the first 10-year interval. The second period examinations were completed in 2007. The required VT-3 examinations will be performed during the third period of this 10-year interval. Areas of the reactor building liner adjacent to the moisture barrier (i.e., between liner and concrete) and the moisture barrier are subject to augmented examination (VT-1, ultrasonic test (UT)).

The TMI-1 aging management program complies with Subsection IWE for metallic shell and penetration liners of Class CC pressure retaining components and their integral attachments of ASME Section XI, 1992 Edition including 1992 Addenda in accordance with the provisions of 10 CFR 50.55a.

TMI-1 is committed to replacing the existing steam generators with new Once Through Steam Generators (OTSGs) prior to entering the period of extended operation. Repair/replacement of Reactor Building liner plate, removed for access purposes, will be done in accordance with ASME Section XI, Subsection IWE.

NUREG-1801 Consistency

The TMI-1 ASME Section XI, Subsection IWE aging management program is consistent with the ten elements of aging management program XI.S1, "ASME Section XI, Subsection IWE," specified in NUREG-1801 with the following exception:

Exceptions to NUREG-1801

NUREG-1801 evaluation is based on ASME Section XI, 2001 Edition including 2002 and 2003 Addenda. The current TMI-1 ASME Section XI, Subsection IWE program plan for the First 10-Year Inspection Interval effective from September 9, 2001 through April 19, 2011, approved per 10 CFR 50.55a, is based on ASME Section XI, 1992 Edition including 1992 addenda. The next 10-Year Inspection Interval for TMI-1 will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a 12 months before the start of the inspection interval.

Enhancements

None.

Operating Experience

Industry Operating Experience:

1. In 2000 while performing visual inspection of the containment surfaces prior to the Type A Leak Test, Braidwood Unit 2 identified corrosion of the liner plate in the areas adjacent to the moisture barrier. Loss of material of the ¼" liner was characterized as due to pitting corrosion. Most of the degraded areas had a reduction in thickness of 1/64" to 1/32". The maximum pit depth measured was approximately 3/32".

2. In 2004, NRC issued Information Notice 2004-09," Corrosion of Steel Containment and Containment Liner", which summarized industry identified corrosion of freestanding metallic containments (Mark I) and corrosion of containment liner plate. Corrosion of the liner plate in the area adjacent to the moisture barrier was reported by several plants and was attributed to the degraded moisture barrier (caulk) or in some cases the moisture barrier was not installed during construction.

As noted in the IN 2004-09, implementation of ASME Section XI, Subsection IWE identified that over time, the existing floor-to-containment seal can degrade, allowing moisture into the crevice between the containment liner plate and floor. Small amounts of stagnant water behind the floor seal area promote pitting corrosion. This is consistent with TMI-1 operating experience as described below.

TMI-1 Operating Experience:

1. In 1993, visual inspections of the TMI-1 reactor building liner plate coating identified local areas of degraded coating and surface corrosion of the liner. UT measurements taken in the areas where corrosion was observed showed that the lowest reading is 0.390", which is greater than the nominal plate thickness of 0.375".

2. In 1997, visual inspection of containment identified degradation of the coating and local liner corrosion at elevations 346', 308', and 281'. Corrosion observed at elevations 346', and 308' was limited to surface rust. Examination of the corroded area at elevation 281' revealed local shallow round bottom pits with depths estimated to be ranging from 1/32" to 1/16". The results of these inspections were entered into the corrective action process. Engineering evaluation concluded the liner intended function is not affected by the local corrosion.

3. In 1999, 100% of the accessible portions of the reactor building liner and moisture barrier were examined in accordance with ASME XI, Subsection IWE. Examination results identified areas of degraded coating and local corrosion of the liner plate at several elevations and degradation of the moisture barrier. Six (6) locations adjacent to the moisture barrier at elevation 281’ and 279’ 6” were observed to have loss of material due to corrosion. Other areas were observed to have only surface rust. One location at elevation 374’ was noted to have a depression of 1/16” in diameter, 1/16” deep; but the depression was not due to corrosion.

   UT measurements were taken at the six locations to quantify the reduced liner thickness. Where corrosion appeared to extend into the liner below the concrete floor at elevation 281’, the moisture barrier and the gap filler material were removed to allow for UT measurements of the corroded area. The minimum measured thickness was 0.310” on the 0.375” nominal thickness liner and 0.651” on the 0.75” nominal thickness liner. The results of these examinations were entered into the corrective action process and evaluated by engineering. The evaluation concluded that the reduced thickness of the liner does not impact its intended function.

   Additionally UT thickness measurements were taken at six 12” x 12” grid locations identified for augmented examination during each ISI Period in accordance with IWE-1240. These grids were previously marked on the liner, above the interface of the concrete floor and the moisture barrier, to allow repetitive examination. Each grid was scanned using a D-meter to determine the minimum liner thicknesses. The minimum measured thickness in each grid was greater than the nominal liner thickness of 0.375”; except for one grid where the minimum measurement was 0.354”. Engineering evaluation of the 0.354” thickness concluded that the reduction is acceptable based on provisions of IWE-3122.4, which allows a 10% reduction in the nominal liner thickness or 0.338” for the 0.375” thick liner.

4. In 2003, visual examination in accordance with ASME Section XI, Subsection IWE of liner plate identified local areas of degraded coating, surface corrosion of the liner adjacent to the moisture barrier, and degraded or loss of seal of the moisture barrier. UT thickness measurements were taken at four (4) locations where surface corrosion was observed. The minimum measured thickness was 0.308” as compared to the nominal design plate thickness of 0.375”. Engineering evaluation concluded that the reduced thickness is acceptable and does not impact the intended function of the liner.

5. In 2005, visual inspection of the reactor building observed that the moisture barrier had separated from liner at several locations. Typically, the separation is less than about 1/32 inch. Several instances are between about 1/32 inch and 1/16 inch and are short in length (1 to 2 inches). No significant liner corrosion was observed. As a result of the observed condition, inspection frequency of the moisture barrier was increased to every refueling outage (2 years). Previously the moisture barrier was scheduled for inspection during each IWE examination period (3 years, 4 years, 3 years).

6. In 2007 TMI-1 conducted the 2nd ISI period examinations of the reactor building liner in accordance with ASME Section XI, Subsection IWE. 100% of accessible areas of the liner were visually inspected. The results of the inspection were acceptable and were similar to findings in previous outages. In addition, augmented UT examinations were performed which resulted from previous inspections in 1999 and 2003. The results of the inspection were acceptable and confirmed that sufficient containment liner thickness remains.

   Also in 2007, the entire Reactor Building moisture barrier was replaced during the refueling outage and a 100 percent VT-3 inspection was performed on the excavated region of the liner. The VT-3 examinations indicated some localized corrosion in the exposed area. UT examinations of the liner were performed in these regions. After replacement of the moisture barrier was complete the adjoining service level 1 coating system was repaired. The results of the inspections were acceptable and confirmed that sufficient containment liner thickness remains.

   During the 2007 refueling outage, primary system water was discovered between the Reactor Building sump stainless steel liner and the lowest point of the carbon steel containment liner. This space is filled with concrete. Based on radiological analysis the water was determined to have resulted from primary system leakage about 15 years ago. The cause of the water intrusion was most likely due to previous leakage past a degraded moisture barrier between the Reactor Building reinforced concrete floor and the carbon steel containment liner. Corrosion of the stainless steel sump liner and carbon steel containment liner due to continued exposure to the water was determined not to be an applicable aging mechanism because the pH of the water was greater than 11.5.

   Future augmented inspections under the IWE program will include inspection of previously corroded areas behind the moisture barrier in accordance with IWE (or other alternative approved by the NRC). In addition, a one time inspection will be performed of the liner in the area of the cork down to the horizontal plate. The entire moisture barrier will continue to be visually inspected each refueling outage.

Conclusion

The continued implementation of the TMI-1 ASME Section XI, Subsection IWE aging management program provides reasonable assurance that the aging effects of loss of material (general, pitting, and crevice corrosion), loss of pressure retaining bolting preload, cracking due to cyclic loading, loss of sealing, leakage through containment/deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants) will be adequately managed so that the intended functions of the Reactor Building will be maintained, consistent with the current licensing basis, during the period of extended operation.

B.2.1.25 ASME SECTION XI, SUBSECTION IWL

Program Description

The TMI-1 ASME Section XI, Subsection IWL aging management program is an existing program which implements examination requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWL for reinforced and prestressed concrete containments (Class CC), 1992 Edition with the 1992 Addenda, as mandated by 10 CFR 50.55a. The program requires periodic inspection of accessible reactor building (containment) reinforced concrete, and inspection and testing of a sample of unbonded post-tensioning system as specified by ASME Section XI, Subsection IWL.

Inspection methods are in accordance with ASME Section XI, Subsection IWL. Accessible concrete surfaces of containment walls and tendon gallery are subject to visual (VT-3C) inspection each examination period to detect loss of material, cracking, and loss of bond. Reinforced concrete surfaces are inspected for loss of material, cracking, cracking and expansion, increase in porosity and permeability, and loss of bond. Concrete surfaces that are suspect of degradations and those extending 2' from the bearing plate of tendons examined during the period are subject to VT-1C examination. A sample of each tendon wire type (vertical, hoop, dome) for the post-tensioning system is subject to physical testing (lift-off force) each examination period to determine if the post-tensioning system tendon wires are experiencing loss of prestress. One tendon wire of each type is detensioned each examination period and visually (VT-1) inspected for loss of material. Samples from the detensioned wires are tested for yield strength, ultimate tensile strength, and elongation. The end anchorage for the post-tensioning system is inspected for loss of material. Tendon corrosion protection medium (grease) is tested for alkalinity, water content, water-soluble chlorides, nitrates, and sulfides.

Acceptance criteria specified in the program is in accordance with ASME Section XI, Subsection IWL. The prestressing forces (lift-off) measured for each tendon is compared to the Base Values predicted for the specific tendon at the specific time of the test as described in Regulatory Guide 1.35, Revision 3. Conditions that do not meet acceptance criteria result in a scope expansion to determine the extent of the condition, evaluated for acceptability in accordance with ASME requirements, and entered in corrective action process.

The TMI-1 aging management program compiles with ASME Section XI, Subsection IWL, 1992 Edition including 1992 Addenda, as approved by 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4)(ii), the TMI-1 ISI program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval.

TMI-1 is committed to replacing the existing steam generators with new Once Through Steam Generators (OTSGs) prior to entering the period of extended operation. Repair/replacement of Reactor Building concrete and prestressing system, removed for access purposes, will be done in accordance with ASME Section XI, Subsection IWL.

NUREG-1801 Consistency

The TMI-1 ASME Section XI, Subsection IWL aging management program is consistent with the ten elements of aging management program XI.S2, "ASME Section XI, Subsection IWL," specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

None.

Operating Experience

TMI-1 completed reactor building (containment) 30th and 25th year ISI examinations (Periods 8 and 7) in 2005 and in 2000 respectively. Examinations for these two periods were conducted in accordance with ASME Section XI, Subsection IWL. Prior to the 25th year ISI, examinations were conducted based on the requirement of Regulatory Guide 1.35, Revision 3 as specified in the plant Technical Specifications and the UFSAR. The results of the 30th year examinations and corrective actions for prestressing tendon wires, end anchorage, corrosion protection medium, and concrete surfaces are summarized below.

1. Prestressing Tendon wires

   All tendon forces were above 95% of the predicted values.

   Vertical, hoop and dome tendon normalized group mean forces were all above the minimum required levels.

   Vertical and hoop tendon force trends projected to the latest date for completion of the 35th year ISI were above the minimum required levels for those groups. The unadjusted dome tendon projection was below the minimum required level; the result of a small sample statistical anomaly. A projection using forces adjusted for the mean normalization factor met the acceptance criterion. The dome tendon projection was accepted by evaluation.

   Elongations measured during re-tensioning of de-tensioned dome and hoop tendons were within 10% of previously measured values. The elongation of V-140 exceeded the 10% limit, a condition attributed to anchor head rotation observed during the re-tensioning process. As a result, tendons V-137 and V-141 (like V-140, these curve around the equipment opening) were added to the surveillance sample, de-tensioned, and re-tensioned. Elongation of the two tendons met the 10% acceptance criteria and elongation of tendon V-140 also met the acceptance criteria during the second re-tensioning. On this basis engineering evaluation concluded the initial excess elongation of V-140 is acceptable.

The tensile strength and elongation (at failure) of all wire test samples were above the minimum required values.

2. End Anchorage

   End anchorage hardware was free of active corrosion, cracking and distortion. With two exceptions, button head condition was as documented during construction. One exception was a single button head protruding about 0.1 inch that was not previously documented. Since such a small protrusion could have been easily missed by the construction examinations, this was accepted without further question. Four button heads protruded from the lower anchor head of V-140 both before de-tensioning and after re-tensioning. Since the vertical tendons are tensioned at the top end only, it was concluded that protruding button heads at the lower end could have been overlooked at the time of construction. On this basis, the condition was accepted by evaluation.

   Coating degradation was observed in large areas of several vertical tendon upper end-bearing plates. Some of these areas were rusted. The areas were cleaned to bright metal, primed and painted to prevent further corrosion.

3. Corrosion Protection Medium:

   Water content, corrosive ion concentration and reserve alkalinity of all corrosion protection medium samples selected for testing during this period met acceptance criteria. The follow-up testing of the corrosion protection medium for lower ends of tendons V-86 and V-164, which was recommended during 25th year surveillance, was done and the test results met acceptance criteria. No free water was found at tendon anchorages. Concrete adjacent to end anchorages was free of cracks over 0.01 inches wide. End anchorage covers (grease caps) were free of damage; only a few showed any signs of corrosion protection medium leakage and the leakage observed were deemed to be insignificant.

   Leakage of the corrosion protection medium (grease) has been observed over the years. The leakage is through small cracks in concrete and through the grease end cap seals. The end caps of a sample of tendons with significant grease leakage were removed and inspected. No corrosion was observed on the anchor head, base plate or button heads. The affected seals were replaced and the leaked grease was replaced. Grease leakage is being addressed under the Repetitive Task program.

4. Concrete Surfaces

   Concrete surfaces were free of damage, deterioration other than that previously documented; except for the following:

   Water seeping under three embedded plates on the dome has resulted in some minor leaching of the concrete. These plates extend out from a point close to the dome apex toward the general area of the vent stack on the west side of the containment. This condition was corrected by sealing the concrete to embed interface area with a caulking compound to prevent further entry of water.

   Grout patches have detached from dome surface at two locations leaving depressions that can accumulate water. One location is alongside an embed on the west side of the dome. The other is on the west side of the dome close to the crane rail. These depressions were filled with epoxy grout to prevent ponding and the consequent possibility of progressive freeze-thaw damage.

   Concrete surface areas with previously documented damage and deterioration were re-examined. In all cases, the conditions previously recorded were found to be effectively stable. However, in several of these areas it was determined that repair/restoration work is necessary to ensure against further deterioration. The repair and restoration work was completed in 2006. With one exception, the repaired areas consist of minor restorative work on the concrete surface or sealing against water intrusion. These are not subject to ASME Section XI Repair/ Replacement requirements. The exception is the application of protective coating in the areas where reinforcing steel is exposed on the vertical face of the ring girder. This work falls under the purview of ASME Section XI since the first layer of reinforcing is exposed. The repaired areas will be re-examined during the next ISI examination, Period 9 (2009)

Conclusion

The continued implementation of the TMI-1 ASME Section XI, Subsection IWL aging management program provides reasonable assurance that the aging effects of loss of material, cracking, cracking and expansion, increase in porosity and permeability, and loss of bond in reinforce concrete, loss of prestress of the tendons, and loss of material for tendon wires and end anchorage will be adequately managed so that the intended functions of the Reactor Building (containment) components within the scope of License Renewal will be maintained during the period of extended operation.

B.2.1.26 ASME SECTION XI, SUBSECTION IWF

Program Description

The ASME Section XI, Subsection IWF aging management program is an existing program that consists of periodic visual examination of ASME Section XI Class 1, 2, and 3 piping and component support members for loss of mechanical function, lock-up due to wear, and loss of material. Bolting is also included with these components and inspected for loss of material and for loss of preload by inspecting for missing, detached, or loosened bolts. The program also relies on the design change procedures that are based on EPRI TR-104213 guidance to ensure proper specification of bolting material, lubricant, and installation torque.

The program is implemented through corporate and station procedures, which provide inspection and acceptance criteria consistent with the requirements of ASME Section XI, Subsection IWF 1995 Edition with 1996 Addenda as approved by 10 CFR 50.55(a).

In accordance with 10 CFR 50.55a(g)(4)(ii), the TMI-1 ISI program is updated each successive 120 month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval.

NUREG-1801 Consistency

The TMI-1 ASME Section XI, Subsection IWF aging management program is an existing program that is consistent with NUREG-1801 aging management program XI.S3, ASME Section XI, Subsection IWF with the exception described below.

Exceptions to NUREG-1801

NUREG-1801 evaluation covers the 2001 edition including the 2002 and 2003 Addenda, as approved in 10 CFR 50.55a. The current TMI-1 ISI Program Plan for the Third Ten-Year Inspection Interval effective from April 20, 2001 through April 19, 2011, approved per 10 CFR 50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for TMI-1 will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval.

Enhancements

None.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that loss of mechanical function, lock-up due to wear, loss of material and loss of bolting function (which includes loss of material and loss of preload by inspecting for missing, detached, or loosened bolts) are being adequately managed. The following examples of operating experience provide objective evidence that the TMI-1 ASME Section XI, Subsection IWF program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. Visual examinations conducted in 1999 in accordance with ASME Section XI, Subsection IWF identified non-recordable and recordable indications. Non-recordable indications consist of minor surface rust, loose bolts or nuts, and out of tolerance hot or cold settings for piping and component supports. A total of 166 piping and component supports (40 Class 1, 96 Class 2, 30 Class 3) were examined. Six (6) of the Class 1 supports, 19 of the Class 2 supports, and 2 Class 3 supports required engineering evaluation. Engineering found the 6 Class 1 supports acceptable. Nineteen (19) Class 2 supports required engineering evaluation; 16 of which were found acceptable and 3 were found unacceptable and required repair. The unacceptable condition was due to loose, missing bolts or nuts. As a result of unacceptable conditions, the scope of inspection was expanded 3 times to include additional supports in order to determine the extent of the condition. The scope expansions were in the Main Steam system where, due to the dynamics of the system, many nuts and/or bolts were either loose or missing. Deficiencies identified in all Class 1, 2, or 3 supports were documented, and either accepted by evaluation or repaired to meet design requirements.

2. Visual examinations conducted in 2001, 2003, 2005, in accordance with ASME Section XI, Subsection IWF identified non-recordable indications that consist of minor surface rust, loose bolts or nuts, and out of tolerance hot or cold settings for piping and component supports. The loose bolts and nuts were tightened and the out tolerance settings were restored to meet design requirements. The surface rust was evaluated and determined not to impact the structural integrity of the supports.

3. A nuclear oversight assessment of non-destructive examination (NDE) procedures governed by the ISI program discovered an inspection procedure that was not updated to reflect the currently applicable ASME Code and Addenda editions as referenced in the ISI program. A review was performed to determine any effect from citing the earlier code, and an extent of condition review was performed to ascertain the existence of any similar incorrect code date use. This example provides objective evidence that deficiencies are identified and entered into the corrective action process and that the program is updated as necessary to ensure

that it remains effective for condition monitoring of piping and components within the scope of license renewal.

4. A focused-area self assessment of the TMI-1 ISI program identified improvement items for completeness of program documentation including referencing an NRC issued SER for a weld repair in the program, referencing an NRC issued SER addressing certification of VT-2 examiners in the program, and including information from the repair and replacement program in the work order used as the repair plan. These changes were made in revisions to the program documents and implemented by the work planners. This example provides objective evidence that deficiencies are identified and entered into the corrective action process and that the program is updated as necessary to ensure that it remains effective for condition monitoring of piping and components within the scope of license renewal.

The operating experience of the ASME Section XI, Subsection IWF program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the ASME Section XI, Subsection IWF program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of ASME Section XI, Subsection IWF program are performed to identify the areas that need improvement to maintain the quality performance of the program.

Conclusion

The continued implementation of the TMI-1 ASME Section XI, Subsection IWF aging management program provides reasonable assurance that the aging effects of loss of mechanical function, lock-up due to wear, loss of material and loss of bolting function (which includes loss of material and loss of preload) will be adequately managed so that the intended functions of piping and component supports within the scope of license renewal will be maintained during the period of extended operation.

B.2.1.27 10 CFR PART 50, APPENDIX J

Program Description

The 10 CFR Part 50, Appendix J aging management program is an existing program that provides for detection of age related pressure boundary degradation and loss of leak tightness due to aging effects such as loss of material, loss of sealing, cracking, or loss of preload in the containment and various systems penetrating primary containment. The program also provides for detection of age related degradation in material properties of gaskets, o-rings, and packing materials for the primary containment pressure boundary access points.

The program consists of tests performed in accordance with the regulations and guidance provided in 10 CFR 50 Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,” Option B, Regulatory Guide 1.163, “Performance-Based Containment Leak-Testing Program,” NEI 94-01, “Industry Guideline for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J,” and ANSI/ANS 56.8, “Containment System Leakage Testing Requirements.”

Containment leak rate tests are performed to assure that leakage through the containment and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the Technical Specifications. An integrated leak rate test (ILRT) is performed during a period of reactor shutdown at the frequency specified in 10 CFR Part 50, Appendix J, Option B. Local leak rate tests (LLRT) are performed on isolation valves and containment access penetrations at frequencies that comply with the requirements of 10 CFR 50 Appendix J, Option B.

NUREG-1801 Consistency

The 10 CFR Part 50, Appendix J aging management program is consistent with the ten elements of aging management program XI.S4, "10 CFR Part 50, Appendix J," specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

None.

Operating Experience

The industry has found that the 10 CFR Part 50, Appendix J testing program has been effective in maintaining the pressure integrity of the containment boundaries, including identification of leakage within the various systems’ pressure boundaries.

The Three Mile Island Unit 1 facility has demonstrated experience in effectively maintaining the integrity of the containment boundaries. The operating experience of the 10 CFR 50, Appendix J program has shown a positive trend in performance. This operating experience shows that individual valves on occasion exceed the leakage acceptance test values and repairs are made in accordance with the program, however, the overall leakage total has been generally trending down. Leakage test data in standard cubic centimeters per minute (SCCM) is as follows: 40,247 SCCM in 2001, 23,687 SCCM in 2003, 21,712 SCCM in 2005 and 22,159 SCCM in 2007.

The allowable limit for the maximum leakage is 104,846 SCCM and the latest values represent approximately 20 percent of this value. Based on this data, there is sufficient confidence that the implementation of the 10 CFR 50, Appendix J program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the 10 CFR 50, Appendix J program are performed to identify the areas that need improvement and to identify enhancements to maintain the quality performance of the program.

Conclusion

The 10 CFR Part 50, Appendix J aging management program provides reasonable assurance that the loss of material and changes in material properties aging effects are adequately managed so that containment components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis during the period of extended operation.

B.2.1.28 STRUCTURES MONITORING PROGRAM

Program Description

The Structures Monitoring Program is an existing program that provides for aging management of structures and structural components, including structural bolting, within the scope of license renewal. The program was developed based on guidance in Regulatory Guide 1.160 Revision 2, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and NUMARC 93 01 Revision 2, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," to satisfy the requirement of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,"

The scope of the program also includes condition monitoring of masonry walls and water-control structures as described in the Masonry Wall Program and in the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants, aging management program. As a result, the program elements incorporate the requirements of NRC IEB 80-11, "Masonry Wall Design", the guidance in NRC IN 87-67, "Lessons learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11", and the requirements of NRC Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants."

The program consists of periodic visual inspections by qualified personnel to monitor structures and components for applicable aging effects. Specifically, concrete structures are inspected for loss of material, cracking, and a loss of bond. Steel components are inspected for loss of material due to corrosion. Masonry walls are inspected for cracking, and elastomers will be monitored for a loss of sealing. Earthen structures associated with water-control structures will be inspected for loss of material and loss of form. Component supports will be inspected for loss of material, reduction or loss of isolation function, and reduction in anchor capacity due to local concrete degradation. Exposed surfaces of bolting are monitored for loss of material, due to corrosion, loose nuts, missing bolts, or other indications of loss of preload. The program also relies on the design change procedures that are based on EPRI TR-104213 guidance to ensure proper specification of bolting material, lubricant, and installation torque.

The scope of the program will be enhanced to include structures that are not monitored under the current term but require monitoring during the period of extended operation. Details of the enhancements are discussed below.

Inspection frequency is every 5 years maximum, with provisions for more frequent inspections to ensure that observed conditions that have the potential for impacting an intended function are evaluated or corrected in accordance with the corrective action process.

NUREG-1801 Consistency

The Structures Monitoring Program is consistent with the ten elements of aging management program XI.S6,"Structures Monitoring Program," specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

- Include Service Building, UPS Diesel Building, Mechanical Draft Cooling Tower Structures, Miscellaneous Yard Structures (Foundation for condensate storage tank, borated water storage tank, diesel fuel storage tank, altitude tank, duct banks, and manholes)
- Monitor penetration seals that perform flood barrier, shelter, protection, and pressure boundary intended functions.
- Monitor the Intake Canal for loss of material and loss of form
- Monitor electrical panels, junction boxes, instrument panels, and conduits for loss of material due to corrosion
- Monitor ground water chemistry by periodically sampling, testing, and analysis of ground water to confirm that the environment remains non-aggressive for buried reinforced concrete.
- Monitor reinforced concrete submerged in raw water associated with Intake Screen and Pumphouse, Circulating Water Pump House, Mechanical Draft Cooling Tower Structures, Natural Draft Cooling Tower Basins
- Monitor vibration isolators, associated with component supports other than those covered by ASME XI, Subsection IWF, for reduction or loss of isolation function.
- Parameters monitored will be enhanced to include plausible aging mechanisms.
- Monitor concrete structures for a reduction in anchor capacity due to local concrete degradation. This will be accomplished by visual inspection of concrete surfaces around anchors for cracking, and spalling
- Revise acceptance criteria to provide details specified in ACI 349.3R-96.

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

Operating Experience

The TMI-1 Structures Monitoring Program was implemented on the schedule mandated by 10 CFR 50.65(a). Baseline inspections of all structures in the scope of Maintenance Rule were completed in 1999. An additional inspection was completed in 2004 consistent with the program 5-year frequency.

1. The 2004 Inspection of 22 structures in the scope of Maintenance Rule identified no significant degradations that impact the intended function of structures and structural components. Hairline cracks, minor spalling and leaching of calcium hydroxide was observed on concrete surfaces in 2004. The inspectors also observed small cracks in the mortar joints of Turbine Building airshaft masonry wall above elevation 355'. The cracks were also noted in Baseline Inspections completed in 1999 and appear not to have changed since that time.

2. The Flood Dike inspection identified no indication of settlement or slope instability. The riprap is well settled, with no signs of movement or degradation. Three areas of local washout were observed and attributed to occasional high-level river water runoffs rather than by the normal river flow. The areas were evaluated and determined not to pose an immediate threat to the dike integrity. The size and location of the washout areas were entered into the corrective action process and scheduled for visual examination during the dike semi-annual inspection.

3. Silt accumulation was observed at the discharge of the 48-inch diameter Emergency River Water Dump line. The silt covered approximately half the diameter of the pipe outlet, a condition also observed in 1999, during the Baseline inspections. Engineering evaluation concluded that the discharge line remains capable of performing its intended function. The pipe outlet is under Operations Surveillance and is inspected on annual basis to ensure that the discharge line is capable of performing its intended function.

4. Equipment supports including anchorages and equipment foundations have no indications of damage or deterioration that would jeopardize equipment integrity. A missing anchor bolt at the condensate booster pump discharge header support, and a degraded grout pad at the base of the auxiliary boiler stack were observed. The conditions were entered into the corrective action for evaluation and repair.

5. Ground water intrusion was identified in the Air Intake Tunnel. The in-leakage, estimated at 1-2 gpm during wet weather, is attributed to a degraded expansion joint seal. Evaluation of the condition concluded that the sump pumps are capable of removing the inflow water, thus flooding of the tunnel is not a concern. Visual inspection of concrete floor at the expansion joint did not show signs of degradation (leaching, rust stains). Repairs to some of the seal were completed in 2006; with additional repairs to be done in 2007.

   Additional water leaks were observed through small cracks on the tunnel walls and the roof. Minor leaching of calcium hydroxide and minor rust stains were noted at some of the cracks. Engineering evaluation concluded that the observed leaching and rust stains are not an indication of significant concrete degradation or rebar corrosion. The Air Intake Tunnel ground water in-leakage poses no safety concern and its impact on concrete and reinforcement is not significant. The condition was entered into the corrective action process for repair of the seal.

Conclusion

The enhanced TMI-1 Structures Monitoring Program provides reasonable assurance that loss of material, cracking, loss of bond, reduction in anchor capacity due to local degradation of concrete, reduction or loss of isolation function, loss of sealing, loss of preload, and loss of form will be adequately managed so that the intended functions of structures and structural components within the scope of license renewal will be maintained during the period of extended operation.

B.2.1.29 PROTECTIVE COATING MONITORING AND MAINTENANCE PROGRAM

Program Description

The Protective Coating Monitoring and Maintenance Program is an existing program that provides for aging management of Service Level I coatings inside the containment. Service Level I coatings are used in areas where corrosion protection may be required and where coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown. TMI-1 was not originally committed to Regulatory Guide 1.54 for Service Level I coatings because the plant was licensed prior to the issuance of this Regulatory Guide in 1973. Currently, TMI-1 is committed to a modified version of this Regulatory Guide, as described in the response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report. The Protective Coating Monitoring and Maintenance Program provides for inspections, assessment, and repairs for any condition that adversely affects the ability of Service Level I coatings to function as intended.

NUREG-1801 Consistency

The Protective Coating Monitoring and Maintenance Program is consistent with the ten elements of aging management program XI.S8, “Protective Coating Monitoring and Maintenance Program,” specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

None.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that degradation of Service Level I protective coatings are being adequately managed. The following examples of operating experience provide objective evidence that the Protective Coating Monitoring and Maintenance Program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. During inspection of containment coatings in 1997, peeling and delamination was observed on the containment liner in an area approximately 15’ wide by 10’ high. The failure of the coating was attributed to limited inadequate surface preparation during previous liner coating repair work performed during the mid 1980’s. No notable degradation of the liner was observed. Numerous other small areas of surface rusting and coating degradation were observed on the liner. Additionally, the 6” Emergency Feedwater line exhibited significant coating degradation (delamination). The

degraded coating was either immediately repaired or evaluated for repair during the next refueling outage. Where coating repair was deferred, the degraded coating was evaluated and documented in the “unqualified coatings list” in accordance with engineering procedures. This example provides objective evidence that a) the coatings program identifies aging effects prior to the loss of intended function, b) deficiencies found during containment coatings inspections are documented in the corrective action program and evaluated for impact on system operability and intended functions, and c) repair activities are specified when necessary to maintain system intended functions.

2. Refueling outage coating inspections were performed in 2003 on the steel containment liner, concrete containment surfaces, and equipment/piping within the containment. Coating deficiencies such as blistering, chipping, cracking, peeling, rusting, mechanical damage, and missing topcoat were photographically recorded and documented in a Coating Inspection Topical Report and several engineering technical evaluations. Coating deficiencies were evaluated by engineering in accordance with engineering procedures and prioritized as requiring immediate repair or deferred repair. Engineering evaluation was also used to determine coating deficiencies that were acceptable as-is with continued monitoring. Coating deficiencies that were not repaired were evaluated to determine their impact on potential liner degradation and on the containment sump debris analysis. Evaluations were documented in the corrective action program and in engineering technical evaluations. This example provides objective evidence that a) the coatings program identifies aging effects prior to the loss of intended function, b) deficiencies found during containment coatings inspections are documented in the corrective action program and evaluated for impact on system operability and intended functions, and c) repair activities are specified when necessary to maintain system intended functions.

3. Refueling outage coating inspections were performed in 2005 on the steel containment liner, concrete containment surfaces, and equipment/piping within the containment. Coating deficiencies such as blistering, chipping, cracking, peeling, rusting, mechanical damage, and missing topcoat were photographically recorded and documented in engineering technical evaluations. Coating deficiencies were evaluated by engineering in accordance with engineering procedures and prioritized as requiring immediate repair or deferred repair. Engineering evaluation was also used to determine coating deficiencies that were acceptable as-is with continued monitoring. Coating deficiencies that were not repaired were evaluated to determine their impact on potential liner degradation and on the containment sump debris analysis. Evaluations were documented in the corrective action program and in engineering technical evaluations. This example provides objective evidence that a) the coatings program identifies aging

effects prior to the loss of intended function, b) deficiencies found during containment coatings inspections are documented in the corrective action program and evaluated for impact on system operability and intended functions, and c) repair activities are specified when necessary to maintain system intended functions.

4. During the design walkdowns in 2006 for the Reactor Building Sump modification, a small amount of coating was found separated from the steel deck under the concrete floor at the 308' and 347' elevations in the Reactor Building. Further inspection revealed that the steel decking had a zinc coating beneath the DBA qualified Carboline 368 primer and Phenoline 368 topcoat protective coating from original construction. Although the protective coating system is DBA qualified, it had not been qualified with the zinc present on the floor decking. Eight samples were shipped to the Keeler and Long DBA Testing facility for analysis. The results of the testing concluded that the coating system was not qualified when applied over the zinc coating on the steel decking. As a result of the testing, a portion of the coating is being tracked as unqualified coating as determined by engineering evaluation. An operability review was performed that indicated that this condition did not adversely impact applicable safety functions. This example provides objective evidence that deficiencies found during containment coatings inspections are documented in the corrective action program and evaluated for impact on system operability and intended functions.

The operating experience of the Protective Coating Monitoring and Maintenance Program provides objective evidence that problems identified would not cause significant impact to the safe operation of the plant and that adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the Protective Coating Monitoring and Maintenance Program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found.

Conclusion

The existing Protective Coating Monitoring and Maintenance Program provides reasonable assurance that aging effects are adequately managed so that the intended functions of Service Level I coatings inside containment are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.30 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

The 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 non-EQ cables and connections within the scope of license renewal that are subject to adverse localized environments. 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.

Cables and connections subject to an adverse environment are managed by visual inspection of the insulation. A sample of accessible electrical cables and connections installed in adverse environments will be visually inspected for signs of accelerated age-related degradation such as embrittlement, discoloration, cracking, or surface contamination. Additional inspections, repair or replacement are initiated as appropriate under the Corrective Action Process.

A sample of accessible cables and connections found to be located in adverse environments will be inspected prior to the period of extended operation, with an inspection frequency of at least once every 10 years. The scope of this program includes inspections of power, control and instrumentation cables and connections located in adverse localized areas.

NUREG-1801 Consistency

The aging management program for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program. The program will be implemented prior to the period of extended operation. Program activities are consistent with the ten elements of aging program XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

None.

Operating Experience

As noted in NUREG-1801, industry operating experience has shown that adverse localized environments caused by heat or radiation for electrical cables and connections may exist next to or above steam generators, pressurizers or hot process pipes, such as feedwater lines. These adverse localized environments have been found to cause degradation of the insulating materials on electrical cables and connections that is visually observable, such as color changes or surface cracking. These visual indications can be used as indications of degradation.

In response to the cable insulation degradation experienced in an adverse localized environment at Turkey Point, TMI-1 evaluated it's configurations for the potential of heat damage to cable insulations. It was determined that TMI-1 did not have the subject design configuration at Turkey Point. Additionally, a few instances of potentially age-related degradation of cables have been identified during the conduct of routine maintenance activities and dispositioned using the corrective action process. In each case, engineering evaluations determined the cause of the apparent degradation, the effect on operability and appropriate corrective action, providing TMI-1 specific operating experience that provides objective evidence demonstrating effectiveness of the corrective action process in identifying and resolving potential age related cable and connection insulation degradation issues. These cases were not significant with respect to current licensing basis or plant safety.

This aging management program is new. Therefore, no programmatic operating experience is available.

Conclusion

The aging management program for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements provides reasonable assurance that aging effects will be adequately managed so that the intended functions of these types of cables and connections are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.31 ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS

Program Description

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program is an existing program that will be enhanced to manage the aging of the cable and connection insulation of the in scope radiation monitoring and nuclear instrumentation circuits in the License Renewal Radiation Monitoring and Nuclear Instrumentation and Incore Monitoring Systems. The in scope radiation monitoring and nuclear instrumentation circuits are sensitive instrumentation circuits with low-level signals and are located in areas where the cables and connections could be exposed to adverse localized environments caused by heat, radiation, or moisture. These adverse localized environments can result in reduced insulation resistance causing increases in leakage currents. Calibration testing and system performance monitoring are currently being performed for in scope radiation monitoring circuits. The current radiation monitoring circuit calibrations will be performed at least once every two years during the period of extended operation. Direct cable testing will be performed as an enhancement to ensure that the cable and connection insulation resistance is adequate for the in scope nuclear instrumentation circuits to perform their intended functions. Nuclear instrumentation direct cable testing will be performed once every 10 years. Based on acceptance criteria related to instrumentation loop performance and cable testing set forth in the calibration and testing procedures, evaluation of unacceptable results is performed under the Corrective Action Process. The in scope radiation monitoring calibration results will be assessed as part of system performance monitoring, for cable aging degradation, once every 10 years, as recommended by NUREG-1801 Section XI.E2. This enhanced aging management program will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The TMI-1 Electrical Cables and Connections Not Subject to 10 CR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program is an existing aging management program that is consistent with NUREG-1801 aging management program XI.E2, Electrical Cables and Connections Not Subject to 10 CR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.

Exceptions to NUREG-1801

None.

Enhancements

The TMI-1 Electrical Cables and Connections Not Subject to 10 CFR 50.59 Environmental Qualification Requirements Used In Instrumentation Circuits aging management program is an existing program that will be enhanced. In scope radiation monitoring circuits are currently tested in alignment with NUREG-1801 aging management program XI.E2, Electrical Cables and Connections Not Subject to 10 CR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits. Existing testing practices will be enhanced by performing direct cable testing for in scope nuclear instrument circuits.

Operating Experience

Industry operating experience has identified occurrences of cable and connection insulation degradation in high voltage, low level instrumentation circuits performing radiation monitoring and nuclear instrumentation functions. The majority of occurrences are related to cable and connection insulation degradation inside of containment near the reactor vessel or to a change in an instrument readout associated with a proximate change in temperature inside the containment.

TMI-1 currently implements instrument circuit calibrations for the in scope radiation monitoring circuits as part of surveillance testing and preventive maintenance. Review of operating experience for these circuits and associated calibrations did not identify significant events attributable to insulation degradation nor a trend indicating age degradation is occurring. Therefore, this operating experience offers objective evidence that current calibration practices are effective in assuring that these circuits will be able to perform their intended functions throughout the period of extended operation.

As an enhancement, TMI-1 will implement direct cable tests for the in scope nuclear instrumentation circuits. This testing is to be added as an enhancement to existing practices which include periodic electronic component calibrations and heat balance computations. Recent TMI-1 operating experience with nuclear instrumentation circuits has resulted in a planned plant change for the replacement of the penetration for the NI-12 Source/Wide Range Nuclear Instrument to correct degraded penetration triaxial connectors. This issue is documented, evaluated and corrected via the Corrective Action Program. The associated issue reports and corrective actions provide objective evidence of proper implementation and effectiveness of the TMI-1 corrective action process in capturing issues, resolving problems and preventing significant occurrences.

The Corrective Action Program documents occurrences when nuclear instruments did not meet test acceptance criteria. Calibrations were subsequently performed, demonstrating appropriate use of the Corrective Action Program and appropriate implementation of corrective actions.

The direct cable testing of in scope nuclear instrumentation circuits is being added as an enhancement and is therefore a new portion to this program. Therefore, no programmatic operating experience is available.

Conclusion

This aging management program Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrument Circuits provides reasonable assurance that aging effects are adequately managed so that the intended functions of these types of cables and connections are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.32 INACCESSIBLE MEDIUM VOLTAGE CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program manages inaccessible medium voltage cables that are exposed to significant moisture simultaneously with significant voltage.

Significant moisture is defined as periodic exposures to moisture that last more than a few days (e.g., cable in standing water). Periodic exposures to moisture that last less than a few days (i.e., normal rain and drain) are not significant. Significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time.

TMI-1's in scope, non-EQ, inaccessible medium voltage cables subject to significant moisture and voltage will be tested as part of this aging management program. These medium voltage cables will be tested using a proven test for detecting deterioration of the insulation system due to wetting, such as power factor, partial discharge, or polarization index, as described in EPRI TR-103834-P1-2, or other testing that is state-of-the-art at the time the test is performed. Cable testing will be performed at least once every 10 years. The first tests will be completed prior to the period of the extended operation.

This aging management program will also inspect manholes associated with the in scope, non-EQ, inaccessible cables subject to significant moisture and voltage, so that draining or other corrective actions can be taken. Inspections for water collection will be performed at a frequency of twice per year, in accordance with existing practices. The first inspections will be completed prior to the period of extended operation.

NUREG-1801 Consistency

The TMI-1 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new aging management program that is consistent with NUREG-1801 aging management program XI.E3, Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

Exceptions to NUREG-1801

None.

Enhancements

None.

Operating Experience

Industry operating experience has shown that cross linked polyethylene or high molecular weight polyethylene insulation materials, exposed to significant moisture and voltage, are most susceptible to water tree formation. Formation and growth of water trees varies directly with operating voltage. TMI-1 has not had an inaccessible medium voltage cable failure. Meggering is the cable testing currently performed. A different test methodology will be used for the implementation of this aging management program. TMI-1 does have operating experience with standing water in its electrical vaults, manways and manholes. Current preventive maintenance practices include twice per year inspections of manholes. If standing water is identified during these inspections, it is removed by pumping.

A NUREG-1801, Section XI.E3 compliant cable testing/condition monitoring aging management program will be implemented prior to the period of extended operation. The current manhole inspection program will remain in effect as a preventative measure to preclude the aging effect.

The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program. Therefore, no programmatic operating experience is available.

Conclusion

The implementation of the TMI-1 Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program provides reasonable assurance that the inaccessible medium voltage cables exposed to significant moisture and significant voltage will be adequately managed so that the intended functions of these cables are maintained consistent with the current licensing basis during the period of extended operation.

B.2.1.33 METAL ENCLOSED BUS

Program Description

The Metal Enclosed Bus aging management program is an existing program that will be enhanced to manage the aging of metal enclosed busses at TMI-1. A sample of accessible bolted connections will be checked for loose connections via thermography. Thermography of metal enclosed busses is an existing TMI-1 predictive maintenance activity. A sample of in scope metal enclosed bus internals are currently visually inspected.

This program, including its enhancements, will be implemented prior to the period of extended operation so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation.

NUREG-1801 Consistency

The Metal Enclosed Bus, when enhanced, is consistent with the ten elements of aging management program XI.E4, “Metal Enclosed Bus,” specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

Thermography of metal enclosed busses is an existing TMI-1 predictive maintenance activity. A sample of in scope metal enclosed bus internals is currently visually inspected. These inspection activities will be enhanced to specify the following inspection criteria:

- Internal portion of the metal enclosed bus will be visually inspected for cracks, corrosion, foreign debris, excessive dust build-up and evidence of moisture intrusion.
- The bus insulation will be visually inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation.
- The internal bus supports will be visually inspected for structural integrity and signs of cracks.

As an additional enhancement, existing metal enclosed bus internal visual inspections will be expanded to include the 480V Metal Enclosed Bus and the Station Black Out Metal Enclosed Bus. This program, including its enhancements, will be implemented prior to the period of extended operation so that the intended functions of components within the scope of License Renewal will be maintained during the period of extended operation.

Operating Experience

Industry experience has shown that failures have occurred on Metal Enclosed Buses caused by cracked insulation and moisture or debris buildup internal to the Metal Enclosed Bus. Experience has also shown that bus connections in the Metal Enclosed Buses exposed to appreciable ohmic heating during operation may experience loosening due to repeated cycling of connected loads. NRC Information Notice IN 2000-14: “Non Vital Bus Fault Leads to Fire and Loss of Offsite Power” and LER 324-06001: “Manual Scram Following a Loss of Startup Auxiliary Transformer” are examples of non-segregated bus duct failures.

A specific review of the thermography results from Preventive Maintenance (PM) repetitive tasks and 1A Aux Transformer bus duct internal inspections did not identify a trend related to aging degradation. A search of the corrective action database has revealed no failures of Metal Enclosed Bus at TMI-1. This TMI-1 specific operating experience offers objective evidence demonstrating effectiveness of current practices, including the Corrective Action Program.

Conclusion

The implementation of the TMI-1 Metal Enclosed Bus aging management program provides reasonable assurance that the loosening of bolted connections due to thermal cycling and ohmic heating; and embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance and electrical failure due to degradation, radiolysis and photolysis of organics; radiation-induced oxidation and moisture intrusion will be adequately managed so that the intended functions of components within the scope of license renewal will be maintained during the period of extended operation.

B.2.1.34 ELECTRICAL CABLE CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new aging management program that will be used to manage the aging effects of metallic parts of cable connections.

The aging effect/mechanism of concern is as follows:

- Loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation.

A representative sample of cable connections within the scope of License Renewal will be selected for one-time testing prior to the period of extended operation to confirm that there is no age related degradation of the electrical connection metallic parts, and if occurring, to determine the extent of any such degradation. The scope of this sampling program will consider application (medium and low voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc). The technical basis for the sample selection will be documented.

The specific type of test performed will be a proven test for detecting loose connections, such as thermography or contact resistance measurement, as appropriate to the application.

NUREG-1801 Consistency

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is consistent with the ten elements of aging management program XI.E6, " Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," specified in NUREG-1801, with exceptions described below.

Exceptions to NUREG-1801

NUREG-1801 describes an aging management program for electrical cable connections in Chapter XI: XI.E6 “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.” An NRC and industry effort is in progress, working towards the issuance of a revision to XI.E6, via the Interim Staff Guidance (ISG) process. The latest draft revision of this ISG was presented for public comment in the September 6, 2007, Vol. 72, No. 172 issue of the Federal Register as: Proposed License Renewal Interim Staff Guidance LR-ISG-2007-02: Changes to Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements” Solicitation of Public Comment. The exception for this aging management program is that the TMI-1 Electrical Cable Connections Not

Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is consistent with NUREG-1801 as it is modified by the September 6, 2007 draft revision of LR-ISG-2007-02.

Enhancements

None.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation are being adequately managed. The following examples of operating experience provide objective evidence that the TMI-1 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. In April 2002, a phase terminal hot spot was discovered by an operator on rounds. It appears the connections loosened due to heating and or vibration. After this event TMI-1 implemented the Exelon corporate Thermography Program Guide MA-AA-716-230-1003 as part of the corrective action.

2. In March of 2003, thermography revealed a hot spot on a breaker load side connection existed. The ‘B’ phase connection was 9 degrees C hotter than the ‘A’ and ‘C’ phases due to a slightly loose lug. This demonstrates effective use of the Thermography Program to detect degraded connections and take appropriate maintenance actions before component failure.

3. In December of 2004, thermography revealed the line side connection was 11 degrees C hotter than the ‘A’ and ‘B’ phases as a result of a loosely crimped lug. This demonstrates effective use of the Thermography Program to detect degraded connections and take appropriate maintenance actions before component failure.

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program. Operating experience has demonstrated that TMI-1 has successfully identified loose connections through the effective use of thermography. There is sufficient confidence that the implementation of the TMI-1 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide confirmation that supports industry operating experience that electrical connections have not experienced a high degree of failures and that existing TMI-1 installation and maintenance practices are effective.

Conclusion

The new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program provides confirmation that the loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation aging effects is either not occurring or being precluded by an effective existing preventive maintenance program. A periodic inspection is therefore not required to assure that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.2.2 PLANT SPECIFIC AGING MANAGEMENT PROGRAMS

This section provides summaries of the plant specific programs credited for managing the effects of aging.

B.2.2.1 NICKEL ALLOY AGING MANAGEMENT PROGRAM

Program Description

The TMI-1 Nickel Alloy Aging Management program is an existing program that provides for managing cracking due to primary water stress corrosion cracking (PWSCC) for nickel alloy components. The Nickel Alloy Aging Management program uses a number of inspection techniques to detect cracking due to PWSCC, including surface examinations, volumetric examinations and bare metal visual examinations. The Nickel Alloy Aging Management program implements the inspection of components through an augmented In-service Inspection (ISI) program. The augmented program administers component evaluations, examination methods, scheduling, and site documentation as required to comply with regulatory, code or industry commitments related to Nickel Alloy issues. The Nickel Alloy Aging Management program includes mitigation and repair activities and strategies to ensure the long-term operability of nickel alloy components. The Nickel Alloy Aging Management program implements applicable Bulletins and Generic Letters and staff-accepted industry guidelines.

Aging Management Program Elements

The results of an evaluation of each element against the 10 elements described in Appendix A of the Standard Review Plan of License Renewal Applications for Nuclear Power Plants, NUREG-1800, are provided below.

Scope of Program – Element 1

The TMI-1 Nickel Alloy Aging Management Program manages cracking due to primary water stress corrosion cracking for nickel alloy components located in the Steam Generator, Reactor Vessel, Reactor Coolant, and Core Flooding system. The components do not include steam generator tubes or secondary side components (included in the Steam Generator Tube Integrity program (B.2.1.8)), reactor vessel internals (included in the PWR Vessel Internals program as described in Table A.5 item 36), or control rod drive mechanism nozzles (included in the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program (B.2.1.5)). The specific locations included are described by the Alloy 600 plan for TMI-1. Currently, the Core Flooding locations are exempt from examination, however, a VT-2 examination is performed in accordance with IWC-2500-1 for these locations. However, future industry events or station evaluations may increase the population of components or allow the exclusion of some components from the scope of the program.

Preventive Actions – Element 2

The Nickel Alloy Aging Management program includes mitigation activities and strategies to ensure the long-term operability of nickel alloy components. Some of the currently available mitigation techniques include weld overlay, replacement with Alloy 690/52/152 and half nozzle repair. The program lists recommended mitigation strategies that are available and considerations to include when selecting a mitigation strategy. The Nickel Alloy Aging Management program is not a performance monitoring program.

Parameters Monitored/Inspected – Element 3

The Nickel Alloy Aging Management program implements the inspection of components through an augmented In-service Inspection (ISI) program. The augmented program administers component evaluations, examination methods, scheduling, and site documentation as required to comply with regulatory, code or industry commitments related to Nickel Alloy issues.

The Nickel Alloy Aging Management program uses a number of inspection techniques to detect cracking due to PWSCC. These include surface examinations, volumetric examinations and bare metal visual examinations. The schedule for the examinations is described in the augmented ISI plan.

The Nickel Alloy Aging Management program is not a performance monitoring program. The Nickel Alloy Aging Management program includes mitigation activities and strategies to ensure the long-term operability of nickel alloy components. Some of the currently available mitigation techniques include weld overlay, replacement with Alloy 690/52/152 and half nozzle repair. The program lists recommended mitigation strategies that are available and considerations to include when selecting a mitigation strategy.

Detection of Aging Effects – Element 4

The Nickel Alloy Aging Management program uses a number of inspection techniques to detect cracking due to PWSCC. These include surface examinations, volumetric examinations and bare metal visual examinations. Bare metal visual examinations are similar to VT-2 examinations but require removal of insulation to allow direct access to the metal surface while pressurized or not pressurized. The nickel alloy components have been ranked based on susceptibility, safety, and economic consequences of degradation/failure. Where applicable, MRP-139 PWSCC susceptibility categories have been assigned to the components.

Detection of cracking due to PWSCC is used to ensure that nickel alloy components meet required design attributes and maintain their availability to perform their intended function as designed when called upon. This program will detect age-related degradation prior to component failure. When required, repair or mitigation is used to ensure that components will meet the design requirements required to perform their intended function.

Nickel Alloy components are inspected in accordance with the augmented In-service Inspection (ISI) plan. The location of the inspection population is detailed in the augmented ISI plan. The schedule for the examinations is described in the augmented ISI plan.

The TMI-1 Nickel Alloy Aging Management program is based on the recommendations of NEI and the EPRI Materials Reliability Program (MRP). Industry experience and research has resulted in recommended techniques and frequencies for inspection to detect cracking prior to component failure.

The TMI-1 Nickel Alloy Aging Management program ranks components based on susceptibility in accordance with MRP guidelines. Inspection population and sample size are in accordance with MRP guidelines.

Monitoring and Trending – Element 5

The TMI-1 Nickel Alloy Aging Management program ranks components based on susceptibility in accordance with MRP guidelines. Inspection frequencies are in accordance with MRP guidelines. Contingencies for repairs are evaluated prior to each inspection outage. Monitoring of industry-operating experience is performed to incorporate any required changes to the Nickel Alloy Aging Management plan as a result of industry experience.

The TMI-1 Nickel Alloy Aging Management inspections are performed as part of an augmented ISI inspection plan. The Nickel Alloy Aging Management program uses a number of inspection techniques to detect cracking due to PWSCC. These include surface examinations, volumetric examinations and bare metal visual examinations. Examination results are evaluated according to regulatory requirements and MRP guidance. Initiation of an issue report to evaluate the examination results is required when acceptance criteria is not met.

Acceptance Criteria – Element 6

Acceptance criteria are specified in the implementing procedure or work order in accordance with the applicable regulatory or industry requirements.

Any acceptance criteria not currently defined in the FSAR will be defined by engineering and accepted based on procedures, regulatory requirements and accepted industry practices.

All qualitative inspections will be performed to the same predetermined criteria as quantitative inspections in accordance with ASME code and approved site procedures.

Corrective Actions – Element 7

Examination results are evaluated according to regulatory requirements and MRP guidance. Initiation of an issue report to evaluate the examination results is required when acceptance criteria is not met.

If the examination results do not meet acceptance criteria, initiation of an issue report to evaluate the examination results is required. Engineering analysis of identified degradation will confirm that the component intended function will be maintained consistent with the current licensing basis, or the component will be repaired or replaced.

Confirmation Process – Element 8

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.

The Nickel Alloy Aging Management program includes mitigation activities and strategies to ensure the long-term operability of nickel alloy components. Follow-up inspections of mitigated components are included in the Nickel Alloy Aging Management program.

When corrective actions are necessary, the corrective action process assures that the cause of the adverse condition is determined and corrective actions are effective in precluding repetition. This process defines how the effectiveness of corrective actions are monitored to prevent recurrence.

Administrative Controls – Element 9

The procedures used to implement the Nickel Alloy Aging Management program are included in the TMI-1 quality assurance program that provides for formal reviews and approvals. Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B.

The Nickel Alloy Aging Management program consists of administratively controlled procedures, which are controlled as stated in item above. This aging management program is included in the TMI-1 license renewal FSAR supplement.

Operating Experience – Element 10

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that cracking due to PWSCC is being adequately managed. The following examples of operating experience provide objective evidence that the Nickel Alloy Aging Management Program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. During refueling outage 15 (Fall 2003), a recordable indication attributed to primary water stress corrosion cracking was identified in the weld that joins the 10” diameter pipe safe-end to the surge nozzle attached to the 36” diameter hot leg. The weld material is Inconel 182. The weld was repaired with a weld overlay during the Fall of 2003, which was approved by the NRC in a safety evaluation. The weld was re-examined during refueling outage 16 (Fall 2005) and found to be acceptable.

2. During refueling outage 15 (Fall 2003), boron was found near the lower Pressurizer Heater Bundles. Further inspections and a root

cause analysis determined that the root cause of the leakage was PWSCC of the Alloy 600 heater bundle diaphragm. The diaphragm was replaced with a stainless steel diaphragm plate.

3. During refueling outage 16 (Fall 2005), a proactive mitigation of the Alloy 600 material on the Pressurizer vent nozzle was performed. For the vent nozzle, a half nozzle repair was performed. The lower portion of the original nozzle was left in the Pressurizer. The new upper portion of the nozzle as well as the weld pad on the outside surface of the Pressurizer was changed to stainless steel. Proactive mitigation of three pressurizer relief valve nozzles is planned for refueling outage 17 during the Fall of 2007, level sensing, one sample and one thermowell are planned for 2009 mitigation. In addition, the pressurizer surge nozzle (at the pressurizer) and the decay heat drop line alloy 82/182 welds will be mitigated with a weld overlay during refueling outage 17 in the Fall of 2007. TMI-1 has considered industry issues with mitigation for the pressurizer nozzles. Experience at McGuire with weld overlay design issues has been factored into the TMI-1 planned work for refueling outage 17. TMI-1 has committed to complete inspection or mitigation of the Pressurizer surge, spray, safety and relief valve nozzle welds containing Alloy 82/182 by December 31, 2007.

4. On August 21, 2003, the NRC issued Bulletin 2003-02, requesting that licensees of pressurized-water nuclear power reactors (PWRs) provide information related to the inspections that have been performed on RPV lower head penetrations. TMI-1 responded indicating that VT-2 examinations with the insulation in place had been performed during startup from each refueling outage since at least 1991. TMI-1 also stated that a bare metal visual examination would be performed during refueling outage 15 in the Fall of 2003. TMI-1 performed a remote visual inspection of the 52 bottom mounted instrumentation nozzles and the RPV lower head in the Fall of 2003. There was no indication of bottom mounted instrumentation nozzle leakage, no lower RPV boric acid leakage, and no RPV base metal wastage observed.

The operating experience of the Nickel Alloy Aging Management Program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. There is sufficient confidence that the implementation of the program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the program are performed to identify the areas that need improvement to maintain the quality performance of the program.

NUREG-1800 Consistency

The TMI-1 Nickel Alloy Aging Management program is a plant-specific program that meets all of the elements of an aging management program as defined in NUREG-1800.

Exceptions to NUREG-1800

None.

Enhancements to NUREG-1800

None.

Conclusion

The Nickel Alloy Aging Management program provides reasonable assurance that cracking due to PWSCC will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

B.3 NUREG-1801 CHAPTER X AGING MANAGEMENT PROGRAMS

B.3.1.1 METAL FATIGUE OF REACTOR COOLANT PRESSURE BOUNDARY

Program Description

The TMI-1 Metal Fatigue of Reactor Coolant Pressure Boundary program is an existing program credited for managing fatigue of reactor coolant pressure boundary components and other components. The program tracks the number of occurrences of significant thermal and pressure transients and compares the cumulative cycles to the number of design cycles, which are considered limits. Several categories of transients are monitored, including reactor trips, heatups and cooldowns, power changes, secondary side temperature changes, hydrostatic tests, and high-pressure injection cycles. Corrective actions are required if the cumulative cycle count approaches 80 percent of a transient cycle design limit or transient cycle administrative limit to assure the limit is not exceeded.

The effect of the reactor coolant environment on TMI-1 fatigue usage has been evaluated for the sample components identified in NUREG/CR-6260 applicable for TMI-1 as a Babcock and Wilcox plant. The method for adjusting fatigue usage to address reactor water environmental effects was to multiply the current Cumulative Usage Factor (CUF) by 1.5 (60/40) to account for 60 years and to further multiply it by an environmental fatigue correction factor applicable for the material type using methodology from NUREG/CR-6583 for carbon and low-alloy steel and NUREG/CR-5704 for stainless steel. This resulted in fatigue usage values greater than 1.0 for certain components, which is unacceptable. Therefore, fatigue will be managed for these components using the Metal Fatigue of Reactor Coolant Pressure Boundary aging management program to assure fatigue usage is not permitted to exceed 1.0 during the period of extended operation. Calculations were prepared to determine how many transient cycles these components could experience without having environmentally adjusted fatigue usage exceeding 1.0, and these reduced numbers of cycles will be imposed as transient cycle administrative limits in the program prior to the period of extended operation.

Prior to the period of extended operation, the program will also be enhanced to add the statement: “Acceptable corrective actions include: reanalysis of the component to demonstrate that the design code limit will not be exceeded prior to or during the period of extended operation, repair of the component, replacement of the component, or other methods approved by the NRC.”

The program will be further enhanced to require consideration of environmental fatigue for additional reactor coolant pressure boundary locations if the cumulative usage factor for one of the environmental fatigue sample locations approaches the design limit of 1.0.

The continued implementation of the TMI-1 Metal Fatigue of Reactor Coolant Pressure Boundary aging management program provides reasonable assurance that fatigue of reactor coolant pressure boundary components will be managed so that the intended functions of the components within the scope of License Renewal will be maintained during the period of extended operation.

NUREG-1801 Consistency

The TMI-1 Metal Fatigue of Reactor Coolant Pressure Boundary program is an existing program that, when enhanced, is consistent with NUREG-1801 aging management program X.M1, Metal Fatigue of Reactor Coolant Pressure Boundary.

Exceptions to NUREG-1801

None.

Enhancements

The TMI-1 Metal Fatigue of Reactor Coolant Pressure Boundary program will be enhanced to add the statement: "Acceptable corrective actions include: reanalysis of the component to demonstrate that the design code limit will not be exceeded prior to or during the period of extended operation; repair of the component; replacement of the component, or other methods approved by the NRC." In addition, the program will be enhanced to require a review of additional reactor coolant pressure boundary locations if the usage factor for one of the environmental fatigue sample locations approaches its design limit.

Operating Experience

The Transient Cycle Logbook has been satisfactorily maintained in the TMI-1 control room, and appropriate entries have been made when transients have occurred throughout plant operational periods. Additional data has been recorded for future use in characterizing each transient if a more rigorous analysis is ever needed. No transient limits have been approached or exceeded. Therefore, the program has been effective in assuring that the reactor coolant pressure boundary components have not been exposed to more transient cycles than they are analyzed for in the applicable fatigue analyses. The operating experience regarding this program is related to updating the transient cycle limits when revisions have been made to fatigue analyses that changed the number of acceptable cycles. The following examples demonstrate that the program has been appropriately reviewed when these changes occurred and updates were made when required.

Fatigue analyses have been revised when necessary to account for unanticipated transients that have been discovered in operating plants. Two examples are pressurizer surge line thermal stratification transients and pressurizer insurge/outsurge transients that were not addressed in the original design analyses. Once they were identified, additional monitoring was performed at Oconee Unit 1 to characterize the transients, and a revised analysis was prepared that accounted for them. The revised analyses increased the fatigue usage associated with certain transients but no changes were made to the numbers of cycles, so no changes were required to the cycle limits in the monitoring program.

5. The HPI nozzle analyses were revised to account for a modification in the piping arrangement, resulting in revised numbers of cycles, which were incorporated into the monitoring program as revised limits.

Conclusion

The enhanced TMI-1 Metal Fatigue of Reactor Coolant Pressure Boundary program manages cumulative fatigue damage of reactor coolant pressure boundary components by assuring that the associated Time-Limited Aging Analyses remain valid through the period of extended operation. This is accomplished by tracking the number of occurrences of plant transients that are significant contributors to fatigue usage for these components, including the transient types listed in UFSAR Table 4.1-1. The cumulative cycle counts are compared to the design cycle limits to assure they are not exceeded. Corrective actions are required if the cumulative cycle count approaches 80 percent of a transient cycle design limit or transient cycle administrative limit to assure the limit is not exceeded. Acceptable corrective actions include reanalysis, repair or replacement of the component. This will assure that the design fatigue analyses will remain valid through the period of extended operation.

The effect of the reactor water environment upon fatigue has been evaluated on a sample of components listed in NUREG/CR-6260 for Babcock and Wilcox plants. Each of these environmental fatigue analyses were shown to have an environmentally adjusted Cumulative Usage Factor less than 1.0 for 60 years of operation based upon reduced numbers of transients that will be imposed as transient cycle administrative limits prior to the period of extended operation. This will assure that the environmental fatigue analyses will also remain valid through the period of extended operation.

B.3.1.2 CONCRETE CONTAINMENT TENDON PRESTRESS

Program Description

The TMI-1 Concrete Containment Tendon Prestress aging management program is an existing program that is part of the TMI-1 ASME Section XI, Subsection IWL Program. The program is based on the 1992 Edition, with 1992 Addenda, of the ASME Boiler and Pressure Vessel Code, Section XI and includes confirmatory actions that monitor loss of containment tendon prestressing forces during the current term and will continue through the period of extended operation.

The program requires measurement of prestressing forces in a 2% sample of each tendon group (vertical, hoop, dome) every five years. One tendon in each group sample is identified as a common, or control, tendon and is tested during each successive inspection. The remaining tendons in the sample are obtained by randomly selecting tendons from among all of those that have not been previously examined. The initial sample size, which may be expanded if unacceptable conditions are found, is established as specified in Table IWL-2521-1.

Assessments of the results of the tendon prestressing force measurements are performed in accordance with ASME Section XI, Subsection IWL to confirm adequacy of the prestressing forces. The assessment consists of the establishment of (a) acceptance criteria, and (b) trend lines. The acceptance criteria consist of lower limits on the forces in individual tendons and the minimum required prestressing force or value (MRV). The lower limit on the force in an individual tendon is, as specified in Section IWL 3221.1(b), 95% of the force predicted for the tendon at the time of the test. The predicted value for individual tendons is developed consistent with the guidance presented in NRC Regulatory Guide 1.35.1. As long as individual tendon forces remain above 95% of predicted values, there is definitive evidence that actual pre-stressing force loss is not significantly greater than that allowed for in the original design calculations.

Trend lines, one for each tendon group, are constructed using the measured tendon forces and represent the changes in mean vertical, hoop and dome prestressing forces with time. Trend line regression analysis is consistent with NRC Information Notice 99-10, Attachment 3. As long as the trend lines do not fall below the MRV's, the tendon prestress force is acceptable. In accordance with the requirements of 10 CFR 50.55a(b)(2)(viii)(B), an evaluation will be performed if the trend lines predict the prestressing forces in the containment to be below the MRV before the next scheduled inspection.

TMI-1 performed a new analysis based on actual measured forces to establish the trend of prestressing forces through the end of the period of extended operation. The analysis evaluates force trends by group (vertical, hoop and dome) and shows that group mean forces will not fall below applicable Minimum Required Values (MRV's) prior to the March 2010 deadline for the completion of the 35 Year Surveillance, a requirement of 10 CFR 50.55a Par.

(b)(2)(viii)(B). However, as tendon force trends may vary with time, the conclusions regarding long-term (beyond March 2010) performance of the post-tensioning system are subject to change as the analysis is periodically updated to account for data acquired during future surveillances. Analysis of individual tendon forces against predicted values shows that there is, on average, a substantial margin between measured force levels and the acceptance limits (95% of predicted values) established in ASME Section XI, Sub-Section IWL, Par. 3221.1(b).

Loss of containment tendon prestressing forces is a Time-Limited Aging Analysis (TLAA) evaluated in accordance with 10 CFR 54.21(c)(1)(iii) as described in Section 4.7. This program is credited for managing loss of containment tendon prestressing forces through the period of extended of operation.

The TMI-1 tendons are ungrouted, thus a plant specific program or a case-by-case evaluation is not required.

TMI-1 is committed to replacing the existing steam generators with new Once Through Steam Generators (OTSGs) prior to entering the period of extended operation. Repair/replacement and testing of the Reactor Building prestressing system, removed for access purposes, will be done in accordance with ASME Section XI, Subsection IWL.

NUREG-1801 Consistency

The TMI-1 Concrete Containment Tendon Prestress aging management program is consistent with the ten elements of aging management program X.S1, "Concrete Containment Tendon Prestress" specified in NUREG-1801 with the exception below.

Exceptions to NUREG-1801

NUREG-1801 evaluation specifies that acceptance criteria will normally consist of prescribed lower limit (PLL) and the minimum required value (MRV) calculated based on NRC Regulatory Guide 1.35.1 guidance. TMI-1 takes exception to using PLL as acceptance criteria. TMI-1 revised its program to comply with ASME Section XI, Subsection IWL, as mandated by 10 CFR 50.55a. Subsection IWL specifies that acceptance criteria be based on the actual design basis (or base value) forces and not the PLL or the base value forces less the upper bound losses. Therefore, IWL requires measured tendon force to be at least 95% of the base value rather than 95% of the significantly smaller PLL specified in Regulatory Guide 1.35. Thus TMI-1 acceptance criteria are more conservative than NUREG-1801 acceptance criteria.

Enhancements

None.

Operating Experience

The operating experience of the Concrete Containment Tendon Prestress program did not show any adverse trend in performance. Forces were measured, in 1999 and 2004, on the required 2% sample of the total tendons population, as required by TMI-1 Technical Specification surveillance for the Reactor Building prestressing system. The 2% sample, or 12 tendons consist of 3 control tendons (1 vertical, 1 hoop, and 1 dome). The remaining 9 tendons (3 vertical, 4 hoop, and 2 dome) were obtained by randomly selecting tendons from among all of those that have not been previously measured. The measured force in each individual tendon met established acceptance criteria of not less than 95% of the predicted force and MRV for each tendon. Two additional tendons were added to the scope of testing in 2004 because elongation of the adjacent original sample tendon, measured during re-tensioning of tendons de-tensioned for removal of sample wires for testing, exceeded the acceptance limit. The measured forces for the two additional tendons also met acceptance criteria.

For control tendons, the average of all normalized tendon measured forces, was greater than the required minimum average tendon force specified in the UFSAR. Plots of the measured forces, measured force trend line data, and the predicted force trend line exhibit three consistent features.

1. Trend lines fitted to the measured forces all have flatter slopes than the predicted force trend lines and, as expected, all fitted trend lines have a negative slope.

2. 30th year surveillance measured forces and fitted trend line ordinates equal 30.6 years are all above predicted force line ordinates.

These plots provide a positive indication that tendon forces are currently decreasing at a lower than expected rate and, support the conclusion that mean tendon forces will remain above the minimum required value at least until the 35th year surveillance.

Conclusion

The continued implementation of the TMI-1 Concrete Containment Tendon Prestress aging management program provides reasonable assurance that the aging effects of loss of containment tendon prestressing forces will be adequately managed so that the intended functions of reactor building (containment) components within the scope of license renewal will be maintained during the period of extended operation.

B.3.1.3 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRICAL COMPONENTS

Program Description

The Environmental Qualification (EQ) of Electric Components program is an existing program implemented through station procedures and preventive maintenance tasks. The TMI-1 Environmental Qualification (EQ) of Electric Components program complies with 10 CFR 50.49, “Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants.” All EQ equipment is included within the scope of License Renewal. The program provides for maintenance of the qualified life for electrical equipment important to safety within the scope of 10 CFR 50.49. Program activities establish, demonstrate, and document the level of qualification, qualified configuration, maintenance, surveillance and replacement requirements necessary to meet 10 CFR 50.49. Reanalysis addresses attributes of analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, corrective actions if acceptance criteria are not met, and the period of time prior to the end of qualified life when the reanalysis will be completed. Qualified life is determined for equipment within the scope of the Environmental Qualification (EQ) of Electric Components 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 Environmental Qualification (EQ) of Electric Components program addresses the low voltage I&C cable issues, consistent with those described in the closure of Generic Safety Issue 168 (GSI 168), “Environmental Qualification of Electrical Equipment”.

NUREG-1801 Consistency

The Environmental Qualification (EQ) of Electric Components program is an existing program that is consistent with the ten elements of aging management program X.E1, “Environmental Qualification (EQ) of Electrical Components,” specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

None.

Operating Experience

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that the TMI-1 Environmental Qualification (EQ) of Electric Components program is adequately managing EQ components. The following examples of operating experience provide objective evidence that the TMI-1 Environmental Qualification (EQ) of Electric Components program will be effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

1. On 9/15/2005 and 3/13/2006, elevated building area temperatures were observed due to an increase in outside ambient temperatures and equipment failure. Proper evaluation of these conditions through the corrective action program demonstrate that the TMI-1 Environmental Qualification (EQ) of Electric Components program is ensuring that EQ profiles are being met and immediate actions are taken to ensure that the elevated building area temperatures had not caused any components to exceed their qualified life.

2. During the performance of maintenance activities, conditions potentially adverse to maintaining the EQ qualification of components need to be identified and corrected. On 1/6/2004, a degraded EQ motor splice was identified through the corrective action system. It was promptly evaluated for operability impact, specifically to ensure it met the requirements of the EQ file.

3. During procurement activities, EQ qualification of components must be demonstrated prior to being installed in the plant. On 5/18/2004, a component being supplied by a vendor had less than adequate EQ documentation. The installation of the component in the plant was delayed until the proper EQ paperwork was obtained.

The operating experience of the TMI-1 Environmental Qualification (EQ) of Electric Components program did not show any adverse trend in performance. Problems identified would not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. The key elements of the Environmental Qualification (EQ) of Electric Components program are being monitored and effectively implemented. There is sufficient confidence that the implementation of the TMI-1 Environmental Qualification (EQ) of Electric Components program will effectively identify degradation prior to failure. Appropriate guidance for re-evaluation, repair, or replacement is provided for locations where degradation is found. Periodic self-assessments of the TMI-1 Environmental Qualification (EQ) of Electric Components program are performed to identify the areas that need improvement to maintain the quality performance of the program.

Conclusion

The Environmental Qualification (EQ) of Electric Components program provides reasonable assurance that aging effects 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.