From: <George.Beck@exeloncorp.com>
To: <dja1@nrc.gov>
Date: 12/13/2005 6:56:29 AM
Subject: FW: Batch 4 - last 2 0f 9 PBDs due 12/12/05

> -----Original Message-----
> From: Beck, George
> Sent: Monday, December 12, 2005 5:09 PM
> To: Donnie Ashley (E-mail); Greg Cranston (E-mail)
> Cc: Polaski, Fred W.; Hufnagel, John G.
> Subject: Batch 4 - last 2 0f 9 PBDs due 12/12/05
>
> Donnie/Greg,
>
> Here are the remaining two of the nine AMP PBDs that we indicated we would provide by Monday, 12/12/05 (Batch 4). This brings to 28 the total number of upgraded program basis documents that we have provided for the Auditors review. This completes Batch 4.
>
> Attached please find the following two PBDs in Word format: PBD B.1.27, ASME XI, Subsection IWE ; and, PBD B.1.33, Protective Coatings Monitoring and Maintenance Program.
>
> Note that these Word files have been "write" protected to prevent inadvertent revisions to the files. This should not preclude viewing, copying, pasting, etc. Please let us know if there are any problems.
>
> As you know these PBDs are being provided in response to AMP Audit question AMP-147. Also attached is an updated answer to AMP Audit question AMP-147 reflecting this transmittal and noting that all AMP basis documents up through Batch 4 have been provided.
>
> Please let John Hufnagel or me know if there are any questions/problems.
>
> George
>
> > <<PBD B.1.27 ASME Section XI, Subsection IWE Rev 0.doc>>
>
> > <<PBD B.1.33 Protective Coating Monitoring Rev 0.doc>>
> > <<12-12-05 Update to AMP-147 Question.pdf>>

Mail Envelope Properties (439EB6E5.855 : 13 : 63573)

Subject: FW: Batch 4 - last 2 0f 9 PBDs due 12/12/05
Creation Date: 12/13/2005 6:55:36 AM
From: <George.Beck@exeloncorp.com>

Created By: George.Beck@exeloncorp.com

Recipients
nrc.gov
OWGWPO01.HQGWDO01
DJA1 (D. Ashley)

Post Office	Route
OWGWPO01.HQGWDO01	nrc.gov

Files	Size	Date & Time
MESSAGE	2393	13 December, 2005 6:55:36 AM
TEXT.htm	4364	
PBD B.1.27 ASME Section XI, Subsection IWE Rev 0.doc	271360	
PBD B.1.33 Protective Coating Monitoring Rev 0.doc	176640	
12-12-05 Update to AMP-147 Question.pdf	65689	
Mime.822	713322	

Options

Expiration Date:	None
Priority:	Standard
Reply Requested:	No
Return Notification:	None
Concealed Subject:	No
Security:	Standard

PROGRAM BASIS DOCUMENT

PBD-AMP-B.1.27

Revision 0

ASME SECTION XI, SUBSECTION IWE

GALL PROGRAM XI.S1 - ASME SECTION XI, SUBSECTION IWE

Prepared By: ______________________

Reviewed By: ______________________

Program Owner Review: ______________________

Technical Lead Approval: ______________________

Revision History:

Revision	*Prepared by:*	*Reviewed by:*	*Program Owner:*	*Approved by:*
0	*Dennis Davis*	*Ahmed Ouaou*	*Greg Harttraft*	*Fred Polaski*
Date				

Summary of Revisions:

Rev. Number	Reason for the Revision(s)
0	Initial Issue

TABLE OF CONTENTS

1.0 PURPOSE AND METHODOLOGY

1.1 Purpose

The purpose of this Program Basis Document is to document and evaluate those activities of the Oyster Creek ASME Section XI, Subsection IWE aging management program that are credited for managing the aging effects of loss of material, crack initiation and growth, loss of preload, loss of sealing, and fretting or lockup as part of Oyster Creek License Renewal to meet the requirements of the License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

This includes the following:

- The identification of the scope of the program;
- The evaluation of program elements against NUREG-1801;
- The review of Operating Experience to demonstrate program effectiveness;
- The identification of required program enhancements; and
- The identification of Oyster Creek documents required to implement the program

1.2 Methodology

The nuclear power plant License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," describes the License Renewal process and provides requirements for the contents of License Renewal Applications. 10 CFR 54.21(a)(3) states:

"For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the Current Licensing Basis (CLB) for the period of extended operation."

The NRC and the industry identified 10 program elements that are useful in describing an aging management program and then demonstrating its effectiveness. These program elements are described in Appendix A.1, Section A.1.2.3 of the Standard Review Plan. NUREG-1801 uses these program elements in Section XI to describe acceptable aging management programs.

This Program Basis Document provides a comparison of the credited Oyster Creek program with the elements of the corresponding NUREG-1801 Chapter XI program XI.S1. Project Level Instruction PLI-8 "Program Basis Documents" prescribes the methodology for evaluating Aging Management Programs. An evaluation of Oyster Creek's aging management program criteria or activities to those of the NUREG-1801 program elements is performed and a conclusion is reached concerning consistency for each individual program element. A demonstration of overall program effectiveness is made after all program elements are evaluated. Required program enhancements are documented. An overall determination is made as to consistency with the program description in NUREG-1801.

2.0 PROGRAM DESCRIPTION

2.1 Program Description

<u>NUREG-1801:</u>

10 CFR 50.55a imposes the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWE for steel containments (Class MC) and steel liners for concrete containments (Class CC). The full scope of IWE includes steel containment shells and their integral attachments; steel liners for concrete containments and their integral attachments; containment hatches and airlocks; seals, gaskets and moisture barriers; and pressure-retaining bolting. This evaluation covers the 2001 edition[1] including the 2002 and 2003 Addenda, as approved in 10 CFR 50.55a. ASME Code Section XI, Subsection IWE and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing mandated program applicable to managing aging of steel containments, steel liners of concrete containments, and other containment components for license renewal.

The primary ISI method specified in IWE is visual examination (general visual, VT-3, VT-1). Limited volumetric examination (ultrasonic thickness measurement) and surface examination (e.g., liquid penetrant) may also be necessary in some instances. Bolt preload is checked by either a torque or tension test. IWE specifies acceptance criteria, corrective actions, and expansion of the

[1] *An applicant may rely on a different version of the ASME Code, but should justify such use. An applicant may wish to refer to the SOC for an update of 10 CFR § 50.55a to justify use of a more recent edition of the Code.*

inspection scope when degradation exceeding the acceptance criteria is found.

The evaluation of 10 CFR 50.55a and Subsection IWE as an aging management program (AMP) for license renewal is provided below.

Oyster Creek:

The Oyster Creek primary containment is a BWR Mark I steel containment. The Oyster Creek ASME Section XI, Subsection IWE aging management program complies with Subsection IWE for steel containments (Class MC) of ASME Section XI, 1992 Edition with the 1992 Addenda, in accordance with the provisions of 10 CFR 50.55a, and is implemented through a program plan and procedures. The use of the 1992 Edition with the 1992 Addenda is an exception to the NUREG-1801 aging management program XI.S1 as indicated in Section 2.3. The scope of the Oyster Creek ASME Section XI, Subsection IWE aging management program plan and procedures includes steel containment shells and their integral attachments, containment hatches and airlocks, vent system, penetrations, seals, gaskets; and pressure-retaining bolting **(Reference: ER-AA-330, ER-AA-330-007, OC-6).** The containment design does not incorporate a moisture barrier.

In addition the scope of Oyster Creek ASME Section XI, Subsection IWE includes examination of the Containment Vacuum Breakers system pressure-retaining components, including piping and fittings, valve bodies, expansion joints, and closure bolting. The Containment Vacuum Breakers system is considered a part of the Primary Containment and is not covered by ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

The Oyster Creek ASME Section XI, Subsection IWE aging management examination methods used at Oyster Creek are visual examination (general visual, VT-3, VT-1) and limited volumetric examination (ultrasonic thickness measurement) when augmented examinations are required. In the Oyster Creek ASME Section XI, Subsection IWE aging management program bolt preload is not checked by either a torque or tension test, rather acceptance is based on Appendix J testing of associated bolted components and a general visual examination, as authorized in accordance with 10 CFR 50.55a (a)(3)(i) **(Reference: ER-AA-330-007 paragraph 4.7, 4.8, 4.10.3; IS-328227-004 paragraph 3.1.2.1; OC-6 paragraph 3.1.1, Table D-1)**. The Oyster Creek Oyster Creek ASME Section XI, Subsection IWE aging management program plan and procedures specify acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found in accordance with applicable IWE requirements **(Reference: ER-AA-330-007 Paragraph 4.10.3).**

Oyster Creek credits the protective coatings on interior surfaces of the suppression chamber (Torus) shell, and the vent system to mitigate corrosion. In addition Oyster Creek also relies on protective coatings on the exterior surfaces of the drywell shell, in the former sand bed region, to mitigate corrosion in accordance with a current licensing basis (CLB) commitment. For the current term, the protective coatings are monitored on frequency of every other refueling outage under the Protective Coating Monitoring and Maintenance Program. These coated areas will be monitored under the Protective Coating Monitoring and Maintenance Program consistent with ASME Section XI, Subsection IWE requirements during the period of extended operation. This constitutes a new enhancement that will be reflected in Protective Coating Monitoring and Maintenance Program.Containment leak rate tests are conducted in accordance with10 CFR Part 50, Appendix J. The tests are credited for primary containment pressure boundary components to assure that leakage through the primary containment does not exceed leakage limits specified in the Technical Specifications. The tests are described in the Oyster Creek 10 CFR Part 50, Appendix J aging management program.

The upper regions of the drywell shell require augmented examinations in accordance with IWE-1240. Examinations using ultrasonic (UT) thickness measurements are conducted every other refueling to detect loss of material due to corrosion. The UT results are evaluated, and trended to ensure that the drywell shell is capable of performing its intended function throughout the life of the plant. Thus drywell corrosion is a Time-Limited Aging Analysis (TLAA) evaluated in accordance with 10 CFR 54.21 (c) as described in LRA Section 4.7.2.

Under the current term, Oyster Creek is committed to NRC to monitor the former sand bed region drains for water leakage. The commitment is to investigate the source of leakage, take corrective actions, evaluate the impact of the leakage and, if necessary perform additional drywell inspections. This commitment will be implemented during the period of extended operation. This is a new commitment not previously identified in the LRA.

2.2 Overall NUREG-1801 Consistency

The Oyster Creek ASME Section XI, Subsection IWE aging management program is an existing program that is consistent with NUREG-1801 aging management program XI.S1, ASME Section XI, Subsection IWE with the exception described in paragraph 2.3.

2.3 Summary of Exceptions to NUREG-1801

The existing Oyster Creek ASME Section XI, Subsection IWE program is found to be adequate to support the extended period of operation with one exception as noted in Section 2.1 and summarized below.

NUREG-1801 evaluation is based on ASME Section XI, 2001 Edition including 2002 and 2003 Addenda. The current Oyster Creek ASME Section XI, Subsection IWE program plan for the First Ten-Year inspection interval effective from September 9, 1998 through September 9, 2008, approved per 10CFR50.55a, is based on ASME Section XI, 1992 Edition including 1992 addenda. The next 120-month inspection interval for Oyster Creek 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.

2.4 Summary of Enhancements to NUREG-1801

None. The existing Oyster Creek ASME Section XI, Subsection IWE aging management program is found to be adequate to support the extended period of operation with no enhancements.

3.0 EVALUATIONS AND TECHNICAL BASIS

Note

This section is organized by quoting the relevant NUREG-1801 Chapter XI program element (September 2005 version) followed by the related Oyster Creek program attributes and a conclusion of the comparison. Where applicable, the NUREG-1801 program element was separated into logical sub-elements and addressed accordingly.

Implementing procedure references are included in **( )** for information purposes. This information from the source procedure has been either directly extracted from the procedure or summarized for inclusion into this PBD.

3.0 Scope of Program

NUREG-1801:

a) Subsection IWE-1000 specifies the components of steel containments and steel liners of concrete containments within its scope. The components within the scope of Subsection IWE are Class MC pressure-retaining components (steel containments) and their integral attachments; metallic shell and penetration liners of Class CC containments and their integral attachments; containment seals and gaskets; containment pressure-retaining bolting; and metal containment surface areas, including welds and base metal. The concrete portions of containments are inspected in accordance with Subsection IWL.

b) Subsection IWE exempts the following from examination:

(1) Components that are outside the boundaries of the containment as defined in the plant-specific design specification;

(2) Embedded or inaccessible portions of containment components that met the requirements of the original construction code of record;

(3) Components that become embedded or inaccessible as a result of vessel repair or replacement, provided IWE-1232 and IWE-5220 are met; and

(4) Piping, pumps, and valves that are part of the containment system or that penetrate or are attached to the containment vessel (governed by IWB or IWC).

c) 10 CFR 50.55a(b)(2)(ix) specifies additional requirements for inaccessible areas. It states that the licensee is to evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. Examination requirements for containment supports are not within the scope of Subsection IWE.

Oyster Creek:

a) The scope of the Oyster Creek ASME Section XI, Subsection IWE aging management program is consistent with the scope identified in Subsection IWE-1000 and includes the Class MC pressure-retaining components and their integral attachments, containment seals and gaskets, containment pressure-retaining bolting, and metal containment surface areas, including welds and base metal. Oyster Creek utilizes a steel containment; therefore there are no Class CC containment components or their integral attachments inspected in accordance with Subsection IWL **(Reference: OC-6 Paragraph 2.1)**. In addition the scope of Oyster Creek ASME Section XI, Subsection IWE includes examination of the Containment Vacuum Breakers system pressure-retaining components, including piping and fittings, valve bodies, expansion joints, and closure bolting. The Containment Vacuum Breakers system is considered a part of the Primary Containment and is not covered by ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program.

b) The Oyster Creek ASME Section XI, Subsection IWE aging management program incorporated the four following component exemptions that are identified in IWE-1220 **(Reference: OC-6 Paragraph 2.1)**.

(1) Components that are outside the boundaries of the containment as defined in the plant-specific design specification;

(2) Embedded or inaccessible portions of containment components that met the requirements of the original construction code of record; (Certain embedded and inaccessible portions of containment components are inspected as a result of corrosion that reduce the design thickness by using UT thickness measurements taken from the component accessible side. Examination frequency and methods are described in detail in Sections 3.4 and 3.5)

(3) Components that become embedded or inaccessible as a result of vessel repair or replacement, provided IWE-1232 and IWE-5220 are met; and

(4) Piping, pumps, and valves that are part of the containment system or that penetrate or are attached to the containment vessel (Piping, pumps, and valves that are part of the containment system or that penetrate or are attached to the containment vessel are inspected in accordance with the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program).

c) When conditions exist in accessible areas that could indicate the presence of, or result in degradation in inaccessible areas, evaluations are performed to evaluate the acceptability of the inaccessible areas in accordance with 10 CFR 50.55a(b)(2)(ix) **(Reference: OC-6 Paragraph 1.1.1)**. The examination requirements for Class MC component supports are not within the scope of the Oyster Creek ASME Section XI, Subsection IWE aging management program but are within the scope of the ASME Section XI, Subsection IWF Program **(Reference: OC-6 Paragraphs 2.2.2, 3.2, and 4.2).**

The Oyster Creek ASME Section XI, Subsection IWE aging management program plan credits tests performed in accordance with 10 CFR Part 50, Appendix J for leak-tightness of seals, and gaskets. No alternatives to the VT-3 visual examination of the seals and gaskets are performed such as a torque test. The containment design does not incorporate a moisture barrier **(Reference: OC-6 Table D-1).**

The Oyster Creek ASME Section XI, Subsection IWE aging management program manages the aging effect of loss of material, crack initiation and growth, loss of preload, loss of sealing, and fretting or lockup for the containment components, and environments listed in Table 5.2. The implementing documents for this aging management program are listed in Table 5.1 and are described throughout the individual program element discussions. The commitment numbers under which these implementing documents are being revised are contained within the listings in Table 5.1.

<u>Exceptions to NUREG-1801, Element 1:</u>

None.

<u>Enhancements to NUREG-1801, Element 1:</u>

None.

<u>Comparison and Evaluation Conclusion:</u>

This element is consistent with NUREG-1801, Element 1, Scope of Program.

3.1 Preventive Actions

<u>NUREG-1801:</u>

No preventive actions are specified; Subsection IWE is a monitoring program.

<u>Oyster Creek:</u>

The Oyster Creek ASME Section XI, Subsection IWE aging management program utilizes inspections that detect degradation before loss of function. No preventive or mitigating attributes are associated with these activities.

As a mitigating measure, Oyster Creek implements procedures in support of, but not part of the Oyster Creek ASME Section XI, Subsection IWE aging management program, in response to Generic Letter 87-05 to inspect the sand bed region drains for leakage and take corrective actions necessary to minimize the amount and duration of water leakage into the drywell air gap. Sand has been removed from the sand bed region and that portion of the drywell shell exterior was coated to prevent further corrosion.

Exceptions to NUREG-1801, Element 2:

None.

Enhancements to NUREG-1801, Element 2:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 2, Preventive Actions.

3.2 Parameters Monitored or Inspected

NUREG-1801:

Table IWE-2500-1 specifies seven categories for examination. The categories, parts examined, and examination methods are presented in the following table. The first six examination categories (E-A through E-G) constitute the ISI requirements of IWE. Examination category E-P references 10 CFR Part 50, Appendix J leak rate testing. Appendix J leak rate testing is evaluated as a separate AMP for license renewal in XI.S4.

CATEGORY	*PARTS EXAMINED*	*EXAMINATION METHOD[a]*
E-A	*Containment surfaces*	*General visual, visual VT-3*
E-B[b]	*Pressure retaining welds*	*Visual VT-1*
E-C	*Containment surfaces requiring augmented examination*	*Visual VT-1, volumetric*
E-D	*Seals, gaskets, and moisture barriers*	*Visual VT-3*
E-F[b]	*Pressure retaining dissimilar metal welds*	*Surface*

E-G	*Pressure retaining bolting*	*Visual VT-1, bolt torque or tension test*
E-P	*All pressure-retaining components (pressure retaining boundary, penetration bellows, airlocks, seals, and gaskets)*	*10 CFR Part 50, Appendix J (containment leak rate testing)*

[a] *The applicable examination method (where multiple methods are listed) depends on the particular subcategory within each category.*

[b] *These two categories are optional, in accordance with 10 CFR 50.55a(b)(2)(ix)(C).*

Table IWE-2500-1 references the applicable section in IWE-3500 that identifies the aging effects that are evaluated. The parameters monitored or inspected depend on the particular examination category. For Examination Category E-A, as an example, metallic surfaces (without coatings) are examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities. For Examination Category E-D, seals, gaskets, and moisture barriers are examined for wear, damage, erosion, tear, surface cracks, or other defects that may violate the leak-tight integrity.

Oyster Creek:

The Oyster Creek ASME Section XI, Subsection IWE aging management program implements the requirements of IWE by providing General, VT-1, and VT-3 visual examinations and augmented inspections for evidence of aging effects that could affect structural integrity or leak tightness of the primary containment **(Reference: OC-6 Paragraphs 2.0 and 3.0).**

Augmented inspections consist of NDE (Ultrasonic) examinations of sample locations in the drywell spherical and cylindrical shells **(Reference: OC-6 Paragraph 3.1.1).**

The Oyster Creek ASME Section XI, Subsection IWE aging management program addresses the following examination categories described in Table IWE-2500-1 which are the same as those described in NUREG-1801 **(Reference: OC-6 Table D-1).**

Category	Parts Examined	Exam Method
E-A	Containment surfaces	General Visual, Visual VT-3
E-B	Pressure retaining welds	(Excluded per 10 CFR 50.55a(b)(2)(ix)(C) and included in E-A)

E-C	Containment surfaces requiring augmented exams	Visual VT-1, Volumetric
E-D	Seals and gaskets	Visual VT-3
E-F	Pressure retaining dissimilar metal welds	(Excluded per 10 CFR 50.55a(b)(2)(ix)(C) and included in E-A)
E-G	Pressure retaining bolting	Visual VT-1
E-P	All pressure-retaining components (pressure retaining boundary, pene-tration bellows, airlocks, seals, and gaskets)	(10 CFR 50, Appendix J)

Oyster Creek elected not to implement the weld examination requirement for Code Categories E-B and E-F as allowed by 10 CFR 50.55a(b)(2)(ix)(C). However, the weld examinations are included in Categories E-A and E-F as accessible surface area inspections **(Reference: OC-6 Paragraphs 1.1.3 and 4.1).**

The Oyster Creek ASME Section XI, Subsection IWE aging management program plan credits tests performed in accordance with 10CFR50, Appendix J for leak-tightness of seals, gaskets, and bolting. **(Reference: OC-6 Table C-1).** The containment design does not incorporate a moisture barrier.

Examination categories and examination methods of the Primary Containment components is applicable to the Containment Vacuum Breaker system components.

The Oyster Creek ASME Section XI, Subsection IWE aging management program specifies examinations of accessible surfaces to detect the aging effects of loss of material, crack initiation and growth, loss of preload, loss of sealing, and fretting or lockup as addressed in IWE-3500. Loss of material, fretting or lockup is monitored by general visual, visual VT-3, Visual VT-1 as described above. Crack initiation and growth of stainless bellows and loss of sealing of airlocks, seals, and gaskets are by 10 CFR Part 50, Appendix J. Crack initiation and growth for pressure retaining dissimilar welds is by surface examination **(Reference: ER-AA-330-007 Paragraph 4.7 and ER-AA-335-018 Paragraph**

4.5.2.3).

Loss of material in areas subject to augmented inspections is monitored using UT thickness measurements (**Reference: OC-6 paragraph 3.3.1.1; Specification IS-328227-004 paragraph 3.1.3.1; Ref. 4.3.7**)

Loss of material on exterior surfaces of the former sand bed region and the submerged suppression chamber (Torus) shell and other submerged MC components are monitored by visual inspection of the protective coatings in accordance with the Protective Coating and Monitoring aging management program (**Reference: Specification IS-328227-004**)

Exceptions to NUREG-1801, Element 3:

None.

Enhancements to NUREG-1801, Element 3:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 3, Parameters Monitored or Inspected.

3.3 Detection of Aging Effects

NUREG-1801:

The frequency and scope of examination specified in 10 CFR 50.55a and Subsection IWE ensure that aging effects would be detected before they would compromise the design-basis requirements. As indicated in IWE-2400, inservice examinations and pressure tests are performed in accordance with one of two inspection programs, A or B, on a specified schedule. Under Inspection Program A, there are four inspection intervals (at 3, 10, 23, and 40 years) for which 100% of the required examinations must be completed. Within each interval, there are various inspection periods for which a certain percentage of the examinations are to be performed to reach 100% at the end of that interval. In addition, a general visual examination is performed once each inspection period. After 40 years of operation, any future examinations will be performed in accordance with Inspection Program B. Under Inspection Program B, starting with the time the plant is placed into service, there is an initial inspection *interval of 10 years and successive inspection intervals of 10 years each, during which 100% of the required examinations are to be completed. An expedited examination of containment is required by 10 CFR 50.55a in which an inservice (baseline) examination specified for the first period of the first inspection interval for containment is to be performed by September 9, 2001. Thereafter, subsequent examinations are performed every 10 years from the baseline examination. Regarding the extent of examination, all accessible surfaces receive a visual examination such as General Visual, VT-1, or VT-3 (see table in item 3 above). IWE-1240 requires augmented examinations (Examination Category E-C) of containment surface areas subject to degradation. A VT-1 visual examination is performed for areas accessible from both sides, and volumetric (ultrasonic thickness measurement) examination is performed for areas accessible from only one side.*

<u>Oyster Creek:</u>

The ASME Section XI, Subsection IWE Inservice Inspection Program Plan for Oyster Creek is prepared and implemented for 10-year intervals, during which 100% of the required examinations are completed. The Oyster Creek ASME Section XI, Subsection IWE aging management program is in accordance with the Inservice Inspection Program B as indicated in IWE-2400. **(Reference: OC-6 Paragraph 2.3.1)**

The inservice (baseline) examination was performed in 2000 and subsequent examinations are being performed every 10 years from the baseline examination. All accessible surfaces are examined in accordance with the requirements delineated in Section 3.3 above **(Reference: OC-6 Paragraph 2.3.1)**.

Augmented examinations are being performed in accordance with the requirements of IWE-1240 (Examination Category E-C) with a VT-1 visual examination for areas accessible from both sides, and volumetric (ultrasonic thickness measurement) examination for areas accessible from only one side **(Reference: OC-6 Paragraph 3.1)**. Examination frequency is every 4 years (every other refueling outage). Augmented examinations consist of ultrasonic thickness measurements in the spherical and the cylindrical regions of the drywell above the sand bed region. Areas subject to UT measurements were selected based on extensive exploratory testing to establish the most severe locations in the drywell above the sand bed region for ongoing inspections **(Reference: SE-000243-002 paragraph 1.2.2)**.

As noted previously, sand has been removed from the former sand bed region and is now accessible during refueling outages for inspection. UT measurements taken in 1992, 1994, and 1996 indicate that corrosion has been stopped and monitoring of the protective coatings is adequate to ensure that any further corrosion will be detected and corrective actions will be taken before a loss of an intended function. The protective coating of the shell in the sand bed region is monitored in accordance with Protective Coating Monitoring and Maintenance Program **(Reference: Specification IS-38227-004; UFSAR section 3.8).**

As discussed with NRC Staff during the AMP audit, Oyster Creek will perform one-time UT thickness measurements of the drywell shell, in the sand bed region, to confirm that the protective coating is effective. The UT measurements will be taken from inside the drywell at the same or approximate locations measured in 1996. *This constitutes a new commitment that will implemented prior to entering the period of extended operation.*

In addition Oyster Creek will monitor the former sand bed region drains for water leakage during each refueling outage during the period of extended operation consistent with an existing current licensing basis (CLB) commitment. Corrective actions will be initiated in accordance with the corrective action process to identify the source of water leakage and evaluate its impact on the drywell shell. **(Reference: 4.3.7)**

The frequency and scope of the Oyster Creek ASME Section XI, Subsection IWE aging management program examinations provide reasonable assurance that evidence of aging effects will be detected prior to loss of intended function.

<u>Exceptions to NUREG-1801, Element 4:</u>

None.

<u>Enhancements to NUREG-1801, Element 4:</u>

None.

<u>Comparison and Evaluation Conclusion:</u>

This element is consistent with NUREG-1801, Element 4, Detection of Aging Effects.

3.4 Monitoring and Trending

NUREG-1801:

a) With the exception of inaccessible areas, all surfaces are monitored by virtue of the examination requirements on a scheduled basis.

b) When component examination results require evaluation of flaws, evaluation of areas of degradation, or repairs, and the component is found to be acceptable for continued service, the areas containing such flaws, degradation, or repairs shall be reexamined during the next inspection period, in accordance with Examination Category E-C. When these reexaminations reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods, these areas no longer require augmented examination in accordance with Examination Category E-C.

c) IWE-2430 specifies that (a) examinations performed during any one inspection that reveal flaws or areas of degradation exceeding the acceptance standards are to be extended to include an additional number of examinations within the same category approximately equal to the initial number of examinations, and (b) when additional flaws or areas of degradation that exceed the acceptance standards are revealed, all of the remaining examinations within the same category are to be performed to the extent specified in Table IWE-2500-1 for the inspection interval.

d) Alternatives to these examinations are provided in 10 CFR 50.55a(b)(2)(ix)(D).

Oyster Creek:

a) The Oyster Creek ASME Section XI, Subsection IWE aging management program provides for periodic inspections for the presence of aging degradation on all accessible surfaces on a scheduled basis **(Reference: OC-6)**. Areas subject to augmented inspection are examined every 4 years (every other refueling outage). The examination results are trended to ensure that required shell thickness meets design requirements **(Reference: Specification IS-328227-004; SE-000243-002 paragraph 1.2)**. Additionally drywell corrosion is considered a Time-Limited Aging Analysis (TLAA) evaluated as described in LRA Section 4.7.2.

b) When examination results require an evaluation or the component is repaired and is found to be acceptable for continued service, the areas containing such flaws, degradation, or repair are reexamined during the next inspection period, in accordance with Examination Category E-C. When the results of these reexaminations remain essentially unchanged for three consecutive inspection periods, the augmented examinations are discontinued in accordance with Examination Category E-C **(Reference: ER-AA-330-007 Paragraph 4.10.4).**

c) The Oyster Creek Oyster Creek ASME Section XI, Subsection IWE aging management program is in accordance with the requirements in IWE-2430 that specify: (a) When examinations reveal flaws or areas of degradation that exceed the acceptance standards, additional examinations are performed within the same examination category and are approximately equal in quantity to the original examinations, and (b) If the additional examinations reveal flaws or areas of degradation, all of the remaining examinations within the same category are performed to the extent specified in Table IWE-2500-1 for the inspection interval **(Reference: ER-AA-330-007 Paragraph 4.10.3).**

d) Alternatives as provided in 10 CFR 50.55a(b)(2)(ix)(D) for dispositioning flaws or areas of degradation may be utilized in the Oyster Creek ASME Section XI, Subsection IWE aging management program **(Reference: OC-6 Paragraph 1.1.4).**

<u>Exceptions to NUREG-1801, Element 5:</u>

None.

<u>Enhancements to NUREG-1801, Element 5:</u>

None.

<u>Comparison and Evaluation Conclusion:</u>

This element is consistent with NUREG-1801, Element 5, Monitoring and Trending.

3.5 Acceptance Criteria

<u>NUREG-1801:</u>

a) IWE-3000 provides acceptance standards for components of steel containments and liners of concrete containments.

b) Table IWE-3410-1 presents criteria to evaluate the acceptability *of the containment components for service following the preservice examination and each inservice examination. This table specifies the acceptance standard for each examination category. Most of the acceptance standards rely on visual examinations. Areas that are suspect require an engineering evaluation or require correction by repair or replacement. For some examinations, such as augmented examinations, numerical values are specified for the acceptance standards. For the containment steel shell or liner, material loss exceeding 10% of the nominal containment wall thickness, or material loss that is projected to exceed 10% of the nominal containment wall thickness before the next examination, are documented. Such areas are to be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.*

Oyster Creek:

a) The acceptance criteria for the Oyster Creek ASME Section XI, Subsection IWE aging management program is in accordance with the requirements of IWE-3000 **(Reference: ER-AA-330-007 Paragraph 4.10).**

b) The acceptance criteria from Table IWE-3410-1 has been incorporated into the Oyster Creek ASME Section XI, Subsection IWE aging management program for the preservice and each inservice examination **(Reference: ER-AA-330-007 Paragraph 4.10)**. When suspect areas are identified, an engineering evaluation or a repair/replacement is performed **(Reference: ER-AA-330-007 Paragraph 4.10.1)**. For the containment drywell shell, instead of documenting the material loss if the loss exceeds 10% of the nominal containment wall thickness, or is expected to exceed 10% of the nominal containment wall thickness before the next examination, Oyster Creek documents all identified material loss at inspection locations **(Reference: ER-AA-330-007 Paragraph 4.13)**. Such areas are accepted by an engineering evaluation or corrected by repair/replacement in accordance with IWE-3122 **(Reference: ER-AA-330-007 Paragraph 4.10.1).**

Exceptions to NUREG-1801, Element 6:

None.

Enhancements to NUREG-1801, Element 6:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria.

3.6 Corrective Actions

NUREG-1801:

Subsection IWE states that components whose examination results indicate flaws or areas of degradation that do not meet the acceptance standards listed in Table-3410-1 are acceptable if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no effect on the structural integrity of the containment. Except as permitted by 10 CFR 50.55a(b)(ix)(D), components that do not meet the acceptance standards are subject to additional examination requirements, and the components are repaired or replaced to the extent necessary to meet the acceptance standards of IWE-3000. For repair of components within the scope of Subsection IWE, IWE-3124 states that repairs and reexaminations are to comply with IWA-4000. IWA-4000 provides repair specifications for pressure retaining components including metal containments and metallic liners of concrete containments. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

Oyster Creek:

Components with flaws or degradation that do not meet the acceptance standards listed in Table-3410-1 can be determined to be acceptable if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature and has no effect on the structural integrity of the component **(Reference: OC-3 Paragraph 4.2.2)**. Except as permitted by 10 CFR 50.55a(b)(ix)(D), components that do not meet the acceptance standards are subject to additional examination requirements, and the components are repaired or replaced to the extent necessary to meet the acceptance standards of IWE-3000 **(Reference: ER-AA-330-007 Paragraph 4.10)**. Repairs and reexaminations, when required, are performed in accordance with IWA-4000 as required by IWE-3124 **(Reference: OC-6 Paragraph 4.3)**. 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.

Evaluations are performed for test or inspection results that do not satisfy established criteria and a condition report is initiated to document the concern in accordance with plant administrative procedures. The 10 CFR 50 Appendix B corrective actions program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be a significant condition adverse to quality, the cause of the condition is determined and an action plan is developed to preclude repetition.

Exceptions to NUREG-1801, Element 7:

None.

Enhancements to NUREG-1801, Element 7:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 7, Corrective Actions.

3.7 Confirmation Process

NUREG-1801:

a) *When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. If the evaluation determines that repair or replacement is necessary, Subsection IWE specifies confirmation that appropriate corrective actions have been completed and are effective. Subsection IWE states that repairs and reexaminations are to comply with the requirements of IWA-4000.*

b) *Reexaminations are conducted in accordance with the requirements of IWA-2200, and the recorded results are to demonstrate that the repair meets the acceptance standards set forth in Table IWE-3410-1. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.*

Oyster Creek:

a) An evaluation is performed when areas of degradation are identified to determine if a repair/replacement is necessary **(Reference: ER-AA-330-007 Paragraph 4.10.1)**. If a repair/replacement is necessary, the Oyster Creek ASME

Section XI, Subsection IWE aging management program requires confirmation that appropriate corrective actions have been completed and are effective **(Reference: ER-AA-330-007 Paragraph 4.10.1)**. Repairs and reexaminations, when required, are performed in accordance with IWA-4000 as required by IWE-3124 **(Reference: OC-3 Paragraph 4.1.2)**.

b) Component reexaminations are conducted in accordance with the requirements of IWA-2200 and the results are recorded to demonstrate that the repair meets the acceptance standards of Table IWE-3410-1 **(Reference: ER-AA-330-007 Paragraph 4.10)**. 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.

<u>Exceptions to NUREG-1801, Element 8:</u>

None.

<u>Enhancements to NUREG-1801, Element 8:</u>

None.

<u>Comparison and Evaluation Conclusion:</u>

This element is consistent with NUREG-1801, Element 8, Confirmation Process.

3.8 Administrative Controls

<u>NUREG-1801:</u>

IWA-6000 provides specifications for the preparation, submittal, and retention of records and reports. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

<u>Oyster Creek:</u>

The Oyster ASME Section XI, Subsection IWE provides specifications for the preparation, submittal, and retention of records in accordance with ASME Section XI IWA-6000 **(Reference: ER-AA-330-007 paragraph 4.10.3, 4.13; OC-6 paragraph 1.1.1, 1.1.4)**. Administrative controls are in accordance with 10 CFR Part 50, Appendix B, see Item 8, above.

<u>Exceptions to NUREG-1801, Element 9:</u>

None.

Enhancements to NUREG-1801, Element 9

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 9, Administrative Controls.

3.9 Operating Experience

NUREG-1801:

ASME Section XI, Subsection IWE was incorporated into 10 CFR 50.55a in 1996. Prior to this time, operating experience pertaining to degradation of steel components of containment was gained through the inspections required by 10 CFR Part 50, Appendix J and ad hoc inspections conducted by licensees and the Nuclear Regulatory Commission (NRC). NRC Information Notice (INs) 86-99, 88-82 and 89-79 described occurrences of corrosion in steel containment shells. NRC Generic Letter (GL) 87-05 addressed the potential for corrosion of boiling water reactor (BWR) Mark I steel drywells in the "sand pocket region." More recently, NRC IN 97-10 identified specific locations where concrete containments are susceptible to liner plate corrosion. The program is to consider the liner plate and containment shell corrosion concerns described in these generic communications. Implementation of the ISI requirements of Subsection IWE, in accordance with 10 CFR 50.55a, is a necessary element of aging management for steel components of steel and concrete containments through the period of extended operation.

Oyster Creek

A review of industry operating experience has confirmed that corrosion has occurred in containment shells. NRC Information Notice (INs) 86-99, 88-82 and 89-79 described occurrences of corrosion in steel containment shells. NRC Generic Letter (GL) 87-05 addressed the potential for corrosion of boiling water reactor (BWR) Mark I steel drywells in the "sand pocket region." More recently, NRC IN 97-10 identified specific locations where concrete containments are susceptible to liner plate corrosion. A review of plant operating experience at Oyster Creek shows that corrosion has occurred in several containment locations. These locations include the drywell shell in the sand bed region, the drywell shell above the sand bed region, and the suppression chamber and vent system. In all cases after being implemented, the Oyster Creek ASME Section XI, Subsection IWE aging management program has identified and corrected the degradation. The experience with the Oyster Creek ASME Section XI, Subsection IWE aging management program shows that the Oyster Creek ASME Section XI, Subsection IWE aging management program is effective in managing aging affects for the primary containment and its components.

Operating experience, both internal and external, is used in two ways at Oyster Creek to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The first way in which operating experience is used is through the Oyster Creek Operating Experience process. 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 both 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.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR 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.

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that aging effects are being adequately managed for the containment components. The following discussion and three examples of operating experience provide objective evidence that the Oyster Creek ASME Section XI, Subsection IWE aging management program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

<u>Discussion</u>:

The Oyster Creek ASME Section XI, Subsection IWE aging management program as described in Oyster Creek 10 Year Containment (IWE) Inservice Inspection Program Plan and Basis **(Reference: OC-6)** is in effect from September 9, 1998 to September 9, 2008. Base line inspection of the drywell was completed during 2000, refueling outage. The suppression chamber (torus) vapor region base line inspection was completed during 2000, refueling outage.

Although the Oyster Creek ASME Section XI, Subsection IWE aging management program implementation is recent, the potential for loss of material, due to corrosion, in inaccessible areas of the containment drywell shell was first recognized in 1980 when water was discovered coming from the sand bed region drains. Corrosion was later confirmed by ultrasonic thickness (UT) measurements taken during the 1986 refueling outage. As a result, several corrective actions were initiated to determine the extent of corrosion, evaluate the integrity of the drywell, mitigate accelerated corrosion, and monitor the condition of containment surfaces. The corrective actions include extensive UT measurements of the drywell shell thickness, removal of the sand in the sand bed region, cleaning and coating exterior surfaces in areas where sand was removed, and an engineering evaluation to confirm the drywell structural integrity. A corrosion monitoring program was established, in 1987, for the drywell shell above the sand bed region to ensure that the containment vessel is capable of performing its intended functions. Elements of the program have been incorporated into the ASME Section XI, Subsection IWE and provide for:

- Periodic UT inspections of the shell thickness at critical locations,
- Calculations which establish conservative corrosion rates,
- Projections of the shell thickness based on the conservative corrosion rates, and
- Demonstration that the minimum required shell thickness is in accordance with ASME code.

Additionally, the NRC was notified of this potential generic issue that later became the subject of NRC Information Notice 86-99 and Generic Letter 87-05. A summary of the operating experience, monitoring activities, and corrective actions taken to ensure that the primary containment will perform its intended functions is discussed below.

Examples of Operating Experience

1. Drywell Shell in the Sand Bed Region:

The drywell shell is fabricated from ASTM A-212-61T Gr. B steel plate. The shell was coated on the inside surface with an inorganic zinc (Carboline carbozinc 11) and on the outside surface with "Red Lead" primer identified as TT-P-86C Type I. The red lead coating covered the entire exterior of the vessel from elevation 8' 11.25" (Fill slab level) to elevation 94' (below drywell flange). .

The sand bed region was filled with dry sand as specified by ASTM 633. Leakage of water from the sand bed drains was observed during the 1980 and 1983 refueling outages. A series of investigations were performed to identify the source of the water and its leak path. The results concluded that the source of water was from the reactor cavity, which is flooded during refueling outages.

As a result of the presence of water in the sand bed region, extensive UT thickness measurements (about 1000) of the drywell shell were taken to determine if degradation was occurring. These measurements corresponded to known water leaks and indicated that wall thinning had occurred in this region.

Because of reduced thickness readings, additional thickness measurements were obtained to determine the vertical profile of the thinning. A trench was excavated inside the drywell, in the concrete floor, in the area where thinning at the floor level was most severe. Measurements taken from the excavated trench indicated that thinning of the embedded shell in concrete were no more severe than those taken at the floor level and became less severe at the lower portions of the sand bed region. Conversely, measurements taken in areas where thinning was not identified at the floor level showed no indication of significant thinning in the embedded shell. Aside from UT thickness measurements performed by plant staff, independent analysis was performed by the EPRI NDE Center and the GE Ultra Image III "C" scan topographical mapping system. The independent tests confirmed the UT results. The GE Ultra Image results were used as baseline profile to track continued corrosion.

To validate UT measurements and characterize the form of damage and its cause (i.e., due to the presence of contaminants, microbiological species, or both) core samples of the drywell shell were obtained at seven locations. The core samples validated the UT measurements and confirmed that the corrosion of the drywell is due to the presence of oxygenated wet sand and exacerbated by the presence of chloride and sulfate in the sand bed region. A contaminate concentrating mechanism due to alternate wetting and drying of the sand may have also contributed to the corrosion phenomenon. It was therefore concluded that the optimum method for mitigating the corrosion is by (1) removal of the sand to break up the galvanic cell, (2) removal of the corrosion product from the shell and (3) application of a protective coating.

Removal of sand was initiated during 1988 by removing sheet metal from around the vent headers to provide access to the sand bed from the Torus room. During operating cycle 13 some sand was removed and access holes were cut into the sand bed region through the shield wall. The work was finished in December 1992 . After sand removal, the concrete surface below the sand was found to be unfinished with improper provisions for water drainage. Corrective actions taken in this region during 1992 included; (1) cleaning of loose rust from the drywell shell, followed by application of epoxy coating and (2) removing the loose debris from the concrete floor followed by rebuilding and reshaping the floor with epoxy to allow drainage of any water that may leak into the region. UT measurements taken from the outside after cleaning verified loss of material projections that had been made based on measurements taken from the inside of the drywell. There were, however, some areas thinner than projected; but in all cases engineering analysis determined that the drywell shell thickness satisfied ASME code requirements. The Protective Coating Monitoring and Maintenance Program was revised to include monitoring of the coatings of exterior surfaces of the drywell in the sand bed region.

The coated surfaces of the former sand bed region were subsequently inspected during refueling outages of 1994, 1996, 2000, and 2004. The inspections showed no coating failure or signs of deterioration. The inspections provide objective evidence that the coating is in a good condition and will provide adequate protection to the drywell shell in the sand bed region. Evaluation of UT measurements taken from inside the drywell, in the in the former sand bed region, in 1992, 1994, and 1996 confirmed that corrosion is mitigated. It is therefore concluded that corrosion in the sand bed region has been arrested and no further loss of material is expected. Monitoring of the coating in accordance with the Protective Coating Monitoring and Maintenance Program, will continue to ensure that the containment drywell shell maintains its intended function during the period of extended operation.

2. Drywell Shell above Sand Bed Region:

The UT investigation phase (1986 through 1991) also identified loss of material, due to corrosion, in the upper regions of the drywell shell. These regions were handled separately from the sand bed region because of the significant difference in corrosion rate and physical difference in design. Corrective action for these regions involved providing a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. Amendment 165 to the Oyster Creek Technical Specifications reduced the drywell design pressure from 62 psig to 44 psig. The new design pressure coupled with measures to prevent water intrusion into the gap between the drywell shell and the concrete will allow the upper portion of the drywell to meet ASME code requirements.

Originally, the knowledge of the extent of corrosion was based on UT measurements going completely around the inside of the drywell at several elevations. At each elevation, a belt-line sweep was used with readings taken on as little as 1" centers wherever thickness changed between successive nominal 6" centers. Six-by-six grids that exhibited the worst metal loss around each elevation were established using this approach and included in the Drywell Corrosion Inspection Program.

As experience increased with each data collection campaign, only grids showing evidence of a change were retained in the inspection program. Additional assurance regarding the adequacy of this inspection plan was obtained by a completely randomized inspection, involving 49 grids that showed that all inspection locations satisfied ASME code requirements. Evaluation of UT measurements taken through 2000 concluded that corrosion is no longer occurring at two (2) elevations, the 3rd elevation is undergoing a corrosion rate of 0.6 mils/year, while the 4th elevations is subject to 1.2 mils/year. The recent UT measurements (2004) confirmed that the corrosion rate continues to decline. The two elevations that previously exhibited no increase in corrosion continue the no corrosion increase trend. The rate of corrosion for the 3rd elevation decreased from 0.6 mils/year to 0.4 mils/year. The rate of corrosion for the 4th elevation decreased from 1.2 mils/year to 0.75 mils/year. After each UT examination campaign, an engineering analysis is performed to ensure the required minimum thickness is provided through the period of extended operation. Thus corrosion of the drywell shell is considered a TLAA further described in Section 4.7.2. These activities provide objective evidence that corrosion of the drywell shell above the sand bed region is adequately managed.

3. Suppression Chamber (Torus) and Vent System

The Oyster Creek suppression chamber (Torus) and vent system were originally coated with Carboline Carbo-Zinc 11 paint. The coating is inspected periodically and repaired to protect the Torus shell and the vent system in accordance with specification SP-1302-52-120. As a result wall thinning of the Torus shell and the vent system has not been an issue. A review of past inspections of the Torus shell and the vent system indicates the majority of the problems found have been attributed to blistering of coating in small areas, localized pitting. In 1983, pitted surfaces of the immersed Torus shell were repair by welding. The Torus shell, the interior of downcomers, and the entire interior surfaces of the vent system were recoated with Mobil 78-Hi Build Epoxy.

Inspection performed in 2002 found the coating to be in good condition in the vapor area of the Torus and vent header, and in fair condition in immersion. Coating deficiencies in immersion include blistering, random and mechanical damage. Blistering occurs primarily in the shell invert but was also noted on the upper shell near the water line. The fractured blisters were repaired to reestablish the protective coating barrier. This is another example of objective evidence that the Oyster Creek ASME Section XI, Subsection IWE aging management program can identify degradation and implement corrective actions to prevent the loss of the containment's intended function.

While blistering is considered a deficiency, it is significant only when it is fractured and exposes the base metal to corrosion attack. The majority of the blisters remain intact and continues to protect the base metal; consequently the corrosion rates are low. Qualitative assessment of the identified pits indicate that the measured pit depths (50 mils max) are significantly less than the criteria established in Specification SP-1302-52-120 (141- 261 mils, depending on diameter of the pit and spacing between pits).

The operating experience of the Oyster Creek ASME Section XI, Subsection IWE 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. The implementation of the Oyster Creek ASME Section XI, Subsection IWE aging management program will effectively identify containment aging effects prior to the loss of the containment function. Appropriate guidance for evaluation, repair, or replacement is provided for locations susceptible to degradation. Periodic self-assessments of the Oyster Creek ASME Section XI, Subsection IWE aging management program are performed to identify the areas that need improvement to maintain the quality performance of the program.

3.10 Conclusion

The Oyster Creek ASME Section XI, Subsection IWE aging management program is credited for managing the aging effects of loss of material, crack initiation and growth, loss of preload, loss of sealing, and fretting or lockup for the systems, components, and environments listed in Table 5.2. The Oyster Creek ASME Section XI, Subsection IWE program's elements have been evaluated against NUREG-1801 in Section 3.0. Program exceptions have been identified in Section 2.3. There are no program enhancements that have been identified in Section 2.4. The implementing documents for this aging management program are listed in Table 5.1. The relevant operating experience has been reviewed and a demonstration of program effectiveness is provided in Section 3.10.

Based on the above, the continued implementation of the Oyster Creek ASME Section XI, Subsection IWE aging management program provides reasonable assurance that aging effects will be adequately managed so that the intended functions of the components within the scope of license renewal will be maintained during the period of extended operation.

4.0 REFERENCES

4.1 Generic to Aging Management Programs

4.1.1 10 CFR 50, Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants

4.1.2 10 CFR 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants

4.1.3 NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, Revision 1,

dated September 2005

4.1.4 NUREG-1801, Generic Aging Lessons Learned (GALL) Report, Revision 1, dated September 2005

4.2 Industry Standards

4.2.1 10 CFR 50.55a, Codes and Standards

4.2.2 10 CFR Part 50, Appendix J, Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors

4.2.3 ASME Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, 1992 Edition with 1992 Addenda; 1995 Edition with 1996 Addenda, 1998 Edition of the ASME Boiler and Pressure Vessel Code

4.2.4 NRC Generic Letter 87-05, Request for Additional Information Assessment of Licensee Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells, U.S. Nuclear Regulatory Commission, March 12, 1987

4.2.5 NRC Information Notice 86-99, Degradation of Steel Containments, U.S. Nuclear Regulatory Commission, December 8, 1986 and Supplement 1, February 14, 1991

4.2.6 NRC Information Notice 88-82, Torus Shells with Corrosion and Degraded Coatings in BWR Containments, U.S. Nuclear Regulatory Commission, October 14,1988 and Supplement 1, May 2, 1989

4.2.7 NRC Information Notice 89-79, Degraded Coatings and Corrosion of Steel Containment Vessels, U.S. Nuclear Regulatory Commission, December 1, 1989 and Supplement 1, June 29, 1989

4.2.8 NRC Information Notice 97-10, Liner Plate Corrosion in Concrete Containment, U.S. Nuclear Regulatory Commission, March 13, 1997

4.3 Oyster Creek Program References

4.3.1 OC-6, Oyster Creek, 10 Year Containment (IWE) Inservice Inspection Program Plan and Basis

4.3.2 SP-1302-06-009, Specification for Application of Service Level I Coatings on Ferrous Metal Surfaces Rev. 3

4.3.3 IS-328227-004, Specification for functional Requirements for Drywell Containment Vessel Thickness Examinations

4.3.4 TDR No. 1108, Summary Report of Corrective Action from Operating Cycle 12 through 14, Revision

4.3.5 ECR 02-01441 Rev. 0, Oyster Creek Drywell Vessel Corrosion Assessment

4.3.6 Calculation No. C-1302-187-E310-037 Rev. 0, Statistical Analysis of Drywell Vessel Thickness Data Through September 2000

4.3.7 Safety Evaluation by the Office of Nuclear Regulation – Drywell Monitoring Program GPU Nuclear Corporation, Oyster Creek Nuclear Generating Station, Docket No. 50-219, NRC letter dated November 1, 1995

4.3.8 Oyster Creek Nuclear Generating Station Updated Final Safety Analysis Report, Revision 13, Section 3.8, Drywell Corrosion

4.3.9 AMP-070, NRC AMP Question and Answer, dated September 23, 2005

4.3.10 AMP-071, NRC AMP Question and Answer, dated September 23, 2005

4.3.11 AMP-072, NRC AMP Question and Answer, dated

September 23, 2005

4.3.12 AMP-118, NRC Question and Answer, dated October 5, 2005

4.3.13 Protective Coating Monitoring and Maintenance Program (B.1.33)

4.3.14 ER-AA-330, Conduct of Inservice Inspection Activities

4.3.15 ER-AA-330-007, Visual Examination of ASME Section XI Class MC and Class CC Surfaces

4.3.16 OC-3 ASME Section XI Repair/Replacement Program

4.3.17 ER-AA-335-018, General VT-1, VT-1C, VT-3, and VT-C3, Visual Examination of ASME Class MC and CC Containment Surfaces and Components

4.3.18 SP-1302-52-120, Specification for Inspection and Localized Repair of the Torus and Vent System Coating"

4.3.19 2400-GMM-3900.52, Inspection and Torquing of Bolted Connections.

4.3.20 SM-AA-300, Procurement Engineering Support Activities.

4.3.21 New PM, Monitoring of Former Sand Bed Region Drains for Water Leakage.

5.0 TABLES

5.1 Aging Management Program Implementing Documents

Procedure Number	Procedure Title	Commitment No.	Status
ER-AA-330	Conduct of Inservice Inspection Activities	330592.27.01	ACC/ASG
ER-AA-330-007	Visual Examination of ASME Section XI Class MC and Class CC Surfaces	330592.27.02	ACC/ASG
PM18703M	Monitor for water leakage in the sand bed region	335092.27.03	ACC/ASG

2400-GMM-3900.52	Inspection and Torquing of Bolted Connections	330592.27.04	ACC/ASG
			ACC/ASG
Specification IS-328227-004	Specification for Functional Requirements for Drywell Containment Vessel Thickness Examinations	330592.27.05	ACC/ASG
OC-6	First 10 Year Containment (IWE) Inservice Inspection Program Plan and Basis	330592.27.06	ACC/ASG
PM18704M	Monitor for water leakage in the sand bed region	330592.27.07	ACC/ASG

5.2 Aging Management Review Results

SSC Name	Structure and/or Component	Material	Environment	Aging Effect
Containment Vacuum Breakers	Piping and fittings	Carbon and low alloy steel	Indoor Air (Internal)	Loss of Material
Containment Vacuum Breakers	Closure bolting	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Containment Vacuum Breakers	Closure bolting	Carbon and low alloy steel	Indoor Air (External)	Loss Of Preload
Containment Vacuum Breakers	Piping and fittings	Stainless Steel	Containment Atmosphere (Internal)	Cracking Initiation and Growth
Containment Vacuum Breakers	Valve Body	Stainless Steel	Containment Atmosphere (Internal)	Cracking Initiation and Growth
Containment Vacuum Breakers	Expansion Joint	Stainless Steel	Containment Atmosphere (Internal)	Cracking Initiation and Growth
Containment Vacuum Breakers	Valve Body	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Containment Vacuum Breakers	Expansion Joint	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Containment Vacuum Breakers	Expansion Joint	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Containment Vacuum Breakers	Piping and fittings	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Containment Vacuum Breakers	Valve Body (Vacuum Breakers)	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Containment Vacuum Breakers	Expansion Joint	Stainless Steel	Indoor Air (External)	Cracking Initiation and Growth
Primary Containment	Drywell Penetration Sleeves	Carbon and low alloy steel, Dissimilar Metal Welds	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Penetration Sleeves	Carbon and low alloy steel, Dissimilar Metal Welds	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Access Hatch Covers	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Penetration Sleeves	Stainless Steel	Containment Atmosphere (Internal)	Cracking
Primary Containment	Drywell Penetration Sleeves	Stainless Steel	Indoor Air (External)	Cracking
Primary Containment	Drywell Penetration Sleeves	Carbon and low alloy steel, Dissimilar Metal Welds	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Downcomers	Carbon and low alloy steel	Treated Water < 140F	Loss of Material
Primary Containment	Locks, Hinges, and Closure Mechanisms	Carbon and low alloy steel	Indoor Air (External)	Loss of Material

Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Downcomers	Carbon and low alloy steel	Containment Atmosphere	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Vent line bellows	Stainless Steel (Dissimilar Metal Welds)	Containment Atmosphere (Internal)	Cracking
Primary Containment	Vent line bellows	Stainless Steel (Dissimilar Metal Welds)	Indoor Air (External)	Cracking
Primary Containment	Drywell Penetration Bellows	Stainless Steel, Dissimilar Metal Welds	Indoor Air (External)	Cracking
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Access Hatch Covers	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Suppression Chamber Ring Girders	Carbon and low alloy steel	Treated Water < 140F (External)	Loss of Material
Primary Containment	Drywell Head	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Head	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Downcomers	Carbon and low alloy steel	Treated Water < 140F	Fretting or lockup
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Penetration Bellows	Stainless Steel, Dissimilar Metal Welds	Containment Atmosphere (Internal)	Cracking
Primary Containment	Drywell Penetration Sleeves	Stainless Steel	Indoor Air (External)	Cracking

Primary Containment	Seals, Gaskets, and O-rings	Elastomer	Containment Atmosphere (External)	Loss of Sealing
Primary Containment	Penetration Closure Plates and Caps (spare penetrations)	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Penetration Closure Plates and Caps (spare penetrations)	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Suppression Chamber Shell Hoop Straps	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Penetration Sleeves	Carbon and low alloy steel, Dissimilar Metal Welds	Indoor Air (External)	Loss of Material
Primary Containment	Vent line, and Vent Header	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Locks, Hinges, and Closure Mechanisms	Carbon and low alloy steel	Containment Atmosphere (External)	Loss of Material
Primary Containment	Suppression Chamber Ring Girders	Carbon and low alloy steel	Containment Atmosphere (External)	Loss of Material
Primary Containment	Drywell Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Shell	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Head	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Shell	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Head	Carbon and low alloy steel	Containment Atmosphere (Internal)	Fretting or lockup
Primary Containment	Drywell Head	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Class MC Pressure Retaining Bolting	Carbon and low alloy steel	Indoor Air	Loss of Material
Primary Containment	Class MC Pressure Retaining Bolting	Carbon and low alloy steel	Containment Atmosphere (External)	Loss of Material
Primary Containment	Personnel Airlock/Equipment Hatch	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Personnel Airlock/Equipment Hatch	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Penetration Sleeves	Stainless Steel	Containment Atmosphere (Internal)	Cracking
Primary Containment	Vent line, and Vent Header	Carbon and low alloy steel	Indoor Air (External)	Loss of Material

6.0 ATTACHMENTS

6.1 LRA Appendix A

6.2 LRA Appendix B

PROGRAM BASIS DOCUMENT

PBD-AMP-B.1.33

Revision 0

PROTECTIVE COATING MONITORING AND MAINTENANCE PROGRAM

GALL PROGRAM XI.S8 - PROTECTIVE COATING MONITORING AND MAINTENANCE PROGRAM

Prepared By: ______________________

Reviewed By: ______________________

Program Owner Review: ______________________

Technical Lead Approval: ______________________

Revision History:

Revision	*Prepared by:*	*Reviewed by:*	*Program Owner:*	*Approved by:*
0	*Mark Miller*	*Stu Getz*	*Giselle Martinez*	*Fred Polaski*
Date				

Summary of Revisions:

Rev. Number	Reason for the Revision(s)
0	Initial Issue

TABLE OF CONTENTS

1.0 PURPOSE AND METHODOLOGY

1.1 Purpose

The purpose of this Program Basis Document is to document and evaluate those activities of the Oyster Creek Protective Coating Monitoring and Maintenance Program aging management program that provide for aging management of Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sandbed region as part of Oyster Creek License Renewal to meet the requirements of the License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

This includes the following:

- The identification of the scope of the program;
- The evaluation of program elements against NUREG-1801;
- The review of Operating Experience to demonstrate program effectiveness;
- The identification of required program enhancements;
- The identification of Oyster Creek documents required implementing the program.

1.2 Methodology

The nuclear power plant License Renewal Rule 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," describes the License Renewal process and provides requirements for the contents of License Renewal Applications. 10 CFR 54.21(a)(3) states:

"For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the Current Licensing Basis (CLB) for the period of extended operation."

The NRC and the industry identified 10 program elements that are useful in describing an aging management program and then demonstrating its effectiveness. These program elements are described in Appendix A.1, Section A.1.2.3 of the Standard Review Plan. NUREG-1801 uses these program elements in Section XI to describe acceptable aging management programs.

This Program Basis Document also provides a comparison of the credited Oyster Creek program with the elements of the corresponding NUREG-1801 Chapter XI program XI.S8, Protective Coating Monitoring and Maintenance Program. Project Level Instruction PLI-8 "Program Basis Documents" prescribes the methodology for evaluating Aging Management Programs. An evaluation of Oyster Creek's aging management program criteria or activities to those of the NUREG-1801 program elements is performed and a conclusion is reached concerning consistency for each individual program element. A demonstration of overall program effectiveness is made after all program elements are evaluated. Required program enhancements are documented. An overall determination is made as to consistency with the program description in NUREG-1801.

2.0 PROGRAM DESCRIPTION

2.1 Program Description

<u>NUREG-1801:</u>

a) *Proper maintenance of protective coatings inside containment (defined as Service Level I in Nuclear Regulatory Commission [NRC] Regulatory Guide [RG] 1.54, Rev. 1) is essential to ensure operability of post-accident safety systems that rely on water recycled through the containment sump/drain system. Degradation of coatings can lead to clogging of strainers, which reduces flow through the sump/drain system. This has been addressed in NRC Generic Letter (GL) 98-04. Maintenance of Service Level I coatings applied to carbon steel surfaces inside containment (e.g., steel liner, steel containment shell, penetrations, hatches) also serves to prevent or minimize loss of material due to corrosion. Regulatory Position C4 in RG 1.54, Rev. 1, describes an acceptable technical basis for a Service Level I coatings monitoring and maintenance program that can be credited for managing the effects of corrosion for carbon steel elements inside containment. The attributes of an acceptable program are described below.*

b) *A comparable program for monitoring and maintaining protective coatings inside containment, developed in accordance with RG 1.54, Rev. 0 or the American National Standards Institute (ANSI) standards (since withdrawn) referenced in RG 1.54, Rev. 0, and coatings maintenance programs described in licensee responses to GL 98-04, is also* *acceptable as an aging management program (AMP) for license renewal.*

Oyster Creek:

a) The Protective Coating Monitoring and Maintenance Program aging management program provides for aging management of Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sandbed region. 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. Service Level II coatings provide corrosion protection and decontaminability in those areas outside of the primary containment that are subject to radiation exposure and radionuclide contamination. The Protective Coating Monitoring and Maintenance Program aging management program provides for visual inspections, assessment, and repairs for any condition that adversely affects the ability of Service Level I coatings, or sandbed region Service Level II coatings, to function as intended. The Protective Coating Monitoring and Maintenance Program aging management program is in accordance with a modified version of Regulatory Guide 1.54 as described in b) below.

b) Oyster Creek was not originally committed to Regulatory Guide 1.54 because the plant was licensed prior to the issuance of this Regulatory Guide in 1974. Currently, Oyster Creek is committed to a modified version of this Regulatory Guide, as described in the Oyster Creek response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10. Oyster Creek's response to GL 98-04 satisfies the requirements for an acceptable coatings maintenance aging management program (AMP) for license renewal as identified in the "Program Description" paragraph of NUREG-1801 Chapter XI program XI.S8, Protective Coating Monitoring and Maintenance Program. The Oyster Creek program for monitoring and maintaining Service Level I coatings inside containment is implemented through specification of appropriate technical and quality requirements of RG 1.54, Rev. 0 and American National Standards Institute (ANSI) N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities" and N101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities". The guidance provided in Electric Power Research Institute (EPRI)

Technical Report TR-109937, "Guidelines on Nuclear Safety-Related Coating" has been evaluated and improvements have been implemented to the program as appropriate.

2.2 Overall NUREG-1801 Consistency

The Oyster Creek Protective Coating Monitoring and Maintenance Program aging management program is an existing program that is consistent with NUREG-1801 aging management program XI.S8, Protective Coating Monitoring and Maintenance Program with enhancement as identified in 2.4 below.

2.3 Summary of Exceptions to NUREG-1801

None. The existing Oyster Creek Protective Coating Monitoring and Maintenance Program aging management program is adequate to support the extended period of operation with no exceptions.

2.4 Summary of Enhancements to NUREG-1801

The inspection of Service Level I and Service Level II protective coatings that are credited for mitigating corrosion on interior surfaces of the Torus shell and vent system, and, on exterior surfaces of the Drywell shell in the area of the sandbed region, will be consistent with ASME Section XI, Subsection IWE requirements.

3.0 EVALUATIONS AND TECHNICAL BASIS

Note

This section is organized by quoting the relevant NUREG-1801 Chapter XI program element (September 2005 version) followed by the related Oyster Creek program attributes and a conclusion of the comparison. Where applicable, the NUREG-1801 program element was separated into logical sub-elements and addressed accordingly.

Implementing procedure references are included in ( ) for information purposes. This information from the source procedure has been either directly extracted from the procedure or summarized for inclusion into this PBD.

3.0 Scope of Program

NUREG-1801:

The minimum scope of the program is Service Level I coatings, *defined in RG 1.54, Rev 1, as follows: "Service Level I coatings are used in areas inside the reactor containment where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown."*

Oyster Creek:

Oyster Creek was not originally committed to Regulatory Guide 1.54 because the plant was licensed prior to the issuance of this Regulatory Guide in 1974. Currently, Oyster Creek is committed to a modified version of this Regulatory Guide, as described in the Oyster Creek response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10. Oyster Creek's response to GL 98-04 satisfies the requirements for an acceptable coatings maintenance aging management program (AMP) for license renewal as identified in the "Program Description" paragraph of NUREG-1801 Chapter XI program XI.S8, Protective Coating Monitoring and Maintenance Program. The Oyster Creek program for monitoring and maintaining Service Level I coatings inside containment is implemented through specification of appropriate technical and quality requirements of RG 1.54, Rev. 0 and American National Standards Institute (ANSI) N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities" and N101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities". The guidance provided in Electric Power Research Institute (EPRI) Technical Report TR-109937, "Guidelines on Nuclear Safety-Related Coating" has been evaluated and improvements have been implemented to the program as appropriate **(Reference: Exelon Quality Assurance Topical Report (QATR) NO-AA-10, Appendix C, Paragraph 1.3.2.6; Letter H. N. Pastis (NRC) to M. B. Roche (GPU Nuclear) dated January 19, 2000, "Completion of Licensing Action for Generic Letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment," dated July 14, 1998; Oyster Creek Nuclear Generating Station (TAC NO. MA4077)"; Letter No. 1940-98-20665 dated November 11, 1998, "Response to Generic Letter 98-04 dated July 14, 1998").**

The scope of the Oyster Protective Coating Monitoring and Maintenance Program aging management program includes the Service Level I coatings inside containment. Service Level I coatings are defined as coatings used in areas inside the reactor containment where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown **(Reference: Procedure ER-AA-330-008, paragraph 2.7.1)**. Service Level I coatings are safety-related. Service Level I coatings are not credited for corrosion protection for the internal Drywell shell. Service Level I coatings are credited for corrosion protection for the Torus and Vent System **(Reference: UFSAR Section 3.8.2.6.2)**.

The Service Level I coating in the Drywell and in the Torus and Vent System is qualified for a LOCA environment. The mass of Drywell coating released following a LOCA jet impingement was conservatively estimated at 47 lbs. No additional coating flaking due to the harsh environment was assumed since the coating is qualified. The coating within the Torus and Vent System is expected to contribute 0 lbs of debris to the suction strainer load following a LOCA. However, it was conservatively assumed in the LOCA debris and transport analysis that 10 lbs of debris is attributed to the Torus and Vent System Service Level I coating. To account for paint located on Drywell equipment, 40 lbs of paint chips were included as part of the design basis loading for the strainers **(Reference: Calculation C-1302-241-E610-081, "Suction Strainer Debris Generation and Transport")**.

The Oyster Creek Protective Coating Monitoring and Maintenance Program aging management program also provides controls for the addition/deletion of undocumented or unqualified Level I coatings of structures, systems, or components inside the reactor containment in order to maintain the amount of undocumented/unqualified coatings within acceptable design limits **(Reference: Procedure CC-AA-205 and Procedure ER-AA-330-008, paragraph 4.16)**.

The Oyster Creek Protective Coating Monitoring and Maintenance Program aging management program includes Service Level II coating activities for the external drywell shell in the area of the sandbed region. Service Level II coatings are defined as coatings used in areas where coatings failure could impair, but not prevent, normal operating performance. The functions of Service Level II coatings are to provide corrosion protection and decontaminability in those areas outside of the reactor containment that are subject to radiation exposure and radionuclide contamination **(Reference: Procedure ER-AA-330-008 paragraph 2.7.2; Specification SP-9000-06-003, paragraph 3.2.1)**. Service Level II coatings are not safety-related. Service Level II coatings are credited for corrosion protection for the external surface of the Drywell in the region of the sandbed **(Reference: UFSAR Section 3.8.2.8)**.

The Oyster Creek Protective Coating Monitoring and Maintenance Program aging management program manages the effects of aging for the systems, components, materials and environments listed in Table 5.2. The implementing documents for this aging management program are listed in Table 5.1 and are described throughout the individual program element discussions. The commitment numbers under which these implementing documents are being revised are contained within the listings in Table 5.1.

Exceptions to NUREG-1801, Element 1:

None.

Enhancements to NUREG-1801, Element 1:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 1, Scope of Program.

3.1 Preventive Actions

NUREG-1801:

With respect to loss of material due to corrosion of carbon steel elements, this program is a preventive action.

Oyster Creek:

With respect to loss of material due to corrosion of carbon steel elements, the Oyster Creek Protective Coating Monitoring and Maintenance Program aging management program is a preventive action. Service Level I protective coatings are maintained and inspected inside the drywell, torus and vent system as a preventative action to minimize loss of material due to corrosion of carbon steel **(Reference: Procedures ER-AA-330-008 and CC-AA-205; Specifications SP-1302-06-009, SP-1302-52-094, and SP-1302-52-120)**. Coatings are not credited for mitigating corrosion in the interior drywell shell; however, drywell containment vessel thickness examinations are performed for the purposes of monitoring and assessing drywell corrosion rates above the sandbed region **(Reference: Specifications IS-328227-004).**

Service Level II protective coating are maintained and inspected on the external drywell shell in the area of the sandbed region to protect the external sandbed region of the containment from corrosion **(Reference: Specifications IS-328227-004, SP-1302-32-035, and SP-9000-06-003).**

<u>Exceptions to NUREG-1801, Element 2:</u>

None.

<u>Enhancements to NUREG-1801, Element 2:</u>

None.

<u>Comparison and Evaluation Conclusion:</u>

This element is consistent with NUREG-1801, Element 2, Preventive Actions.

3.2 Parameters Monitored or Inspected

<u>NUREG-1801:</u>

Regulatory Position C4 in RG 1.54, Rev 1, states that "ASTM D 5163-96 provides guidelines that are acceptable to the NRC staff for establishing an in-service coatings monitoring program for Service Level I coating systems in operating nuclear power plants..." ASTM D 5163-96 has been superseded by ASTM D 5163-05. ASTM D 5163-05, subparagraph 10.2, identifies the parameters monitored or inspected to be "any visible defects, such as blistering, cracking, flaking, peeling, rusting, and physical damage."

<u>Oyster Creek:</u>

Oyster Creek was not originally committed to Regulatory Guide 1.54 because the plant was licensed prior to the issuance of this Regulatory Guide in 1974. Currently, Oyster Creek is committed to a modified version of this Regulatory Guide, as described in the Oyster Creek response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10. Oyster Creek's response to GL 98-04 satisfies the requirements for an acceptable coatings maintenance aging management program (AMP) for license renewal as identified in the "Program Description" paragraph of NUREG-1801 Chapter XI program XI.S8, Protective

Coating Monitoring and Maintenance Program. The Oyster Creek program for monitoring and maintaining Service Level I coatings inside containment is implemented through specification of appropriate technical and quality requirements of RG 1.54, Rev. 0 and American National Standards Institute (ANSI) N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities" and N101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities". The guidance provided in Electric Power Research Institute (EPRI) Technical Report TR-109937, "Guidelines on Nuclear Safety-Related Coating" has been evaluated and improvements have been implemented to the program as appropriate **(Reference: Exelon Quality Assurance Topical Report (QATR) NO-AA-10, Appendix C, Paragraph 1.3.2.6; Letter H. N. Pastis (NRC) to M. B. Roche (GPU Nuclear) dated January 19, 2000, "Completion of Licensing Action for Generic Letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment," dated July 14, 1998; Oyster Creek Nuclear Generating Station (TAC NO. MA4077)"; Letter No. 1940-98-20665 dated November 11, 1998, "Response to Generic Letter 98-04 dated July 14, 1998").**

For Service Level I coatings inside the containment, parameters monitored or inspected include defects such as cracks, sags, runs, flaking, orange peel, overspray, checks, blisters, bubbles, and craters, or any condition that adversely affects the ability of a coating film to function as intended. Other examples of coating defects or deterioration include delamination, holiday, peeling, rusting, spalling, pitting, delamination/peeling, cracking, and/or blistering **(Reference: Procedure ER-AA-330-008; Specifications SP-1302-06-009, SP-1302-52-094, and SP-1302-52-120).**

For Service Level II coating on the external drywell shell in the area of the sandbed region, parameters monitored or inspected include defects such as burn marks, chips/scratches, rust spots, blisters, spalling, peeling, cracking, delamination, flaking or any other types of visible coating defects or signs of distress in the coating **(Reference: Specifications SP-1302-32-035 and SP-9000-06-003).**

<u>Exceptions to NUREG-1801, Element 3:</u>

None.

Enhancements to NUREG-1801, Element 3:

The inspection of Service Level I and Service Level II protective coatings that are credited for mitigating corrosion on interior surfaces of the Torus shell and vent system, and, on exterior surfaces of the Drywell shell in the area of the sandbed region, will be consistent with ASME Section XI, Subsection IWE requirements.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 3, Parameters Monitored or Inspected with enhancement as discussed above.

3.3 Detection of Aging Effects

NUREG-1801:

a) *ASTM D 5163-05, paragraph 6, defines the inspection frequency to be each refueling outage or during other major maintenance outages as needed.*

b) *ASTM D 5163-05, paragraph 9, discusses the qualifications for inspection personnel, the inspection coordinator and the inspection results evaluator.*

c) *ASTM D 5163-05, subparagraph 10.1, discusses development of the inspection plan and the inspection methods to be used. It states, "A general visual inspection shall be conducted on all readily accessible coated surfaces during a walk-through.*

d) *After a walk-through, or during the general visual inspection, thorough visual inspections shall be carried out on previously designated areas and on areas noted as deficient during the walk-through.*

e) *A thorough visual inspection shall also be carried out on all coatings near sumps or screens associated with the Emergency Core Cooling System (ECCS)." This subparagraph also addresses field documentation of inspection results. ASTM D 5163-05, subparagraph 10.5, identifies instruments and equipment needed for inspection.*

Oyster Creek:

Oyster Creek was not originally committed to Regulatory Guide 1.54 because the plant was licensed prior to the issuance of this Regulatory Guide in 1974. Currently, Oyster Creek is committed to a modified version of this Regulatory Guide, as described in the Oyster Creek response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10. Oyster Creek's response to GL 98-04 satisfies the requirements for an acceptable coatings maintenance aging management program (AMP) for license renewal as identified in the "Program Description" paragraph of NUREG-1801 Chapter XI program XI.S8, Protective Coating Monitoring and Maintenance Program. The Oyster Creek program for monitoring and maintaining Service Level I coatings inside containment is implemented through specification of appropriate technical and quality requirements of RG 1.54, Rev. 0 and American National Standards Institute (ANSI) N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities" and N101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities". The guidance provided in Electric Power Research Institute (EPRI) Technical Report TR-109937, "Guidelines on Nuclear Safety-Related Coating" has been evaluated and improvements have been implemented to the program as appropriate **(Reference: Exelon Quality Assurance Topical Report (QATR) NO-AA-10, Appendix C, Paragraph 1.3.2.6; Letter H. N. Pastis (NRC) to M. B. Roche (GPU Nuclear) dated January 19, 2000, "Completion of Licensing Action for Generic Letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment," dated July 14, 1998; Oyster Creek Nuclear Generating Station (TAC NO. MA4077)"; Letter No. 1940-98-20665 dated November 11, 1998, "Response to Generic Letter 98-04 dated July 14, 1998").**

a) ASTM D 5163-05, paragraph 6, states that the "frequency of in-service coating inspection monitoring shall be determined by the owner/operator." It further states that "it is good practice to perform inspections during each refueling outage or during other major maintenance outages as needed." Based on Oyster Creek operating experience, internal drywell surfaces and Service Level I coatings inspections, and, the inspection of the Service Level II coating on the external drywell shell in the area of the sandbed region, are scheduled for every other refueling outage **(Reference: UFSAR Section 3.8.2.8; Specification IS-328227-004, paragraphs 3.1.3.1 and 3.1.3.3;**

Commitment Nos. 00330592.33.09 and 00330592.33.12). The torus and vent system coating in the vapor space is inspected every refueling outage **(Reference: Commitment Nos. 00330592.33.10 and 00330592.33.11).** The underwater portions of this coating is inspected every other refueling outage **(Reference: Commitment No. 00330592.33.10).** The work control system includes activities to ensure the appropriate planning and performance of these inspections.

b) For Service Level I coatings, the Site Coating Coordinator (i.e., Cognizant Engineer who is knowledgeable and experienced in nuclear coatings work) is responsible for the disposition of recordable indications, and, for reviewing and approving inspection work scope. The Site Coatings Coordinator also ensures that inspection personnel are qualified for coatings work on Service Level I Coatings, and, ensures contractor personnel are qualified/certified to Oyster Creek guidelines or to the contractor's certification program, as applicable **(Reference: Procedure ER-AA-330-008, paragraph 3.6).** For Service Level II coating inspections of the sandbed region, inspection specifications ensure that results are reviewed by the Site Coating Coordinator and inspection personnel are qualified/certified **(Reference: Specification IS-328227-004, paragraphs 1.2 and 3.1.1 and Exhibit 4).**

The Oyster Creek quality assurance program is applied to protective coatings consistent with the nature and scope of work specified and includes requirements for training and qualification of inspection personnel in coatings inspection requirements **(Reference: Exelon Quality Assurance Topical Report (QATR) NO-AA-10, Appendix C, Paragraph 1.3.2.6.D.4).**

c) The inspection specification identifies the Service Level I coating to be inspected in the Drywell and requires performing general visual inspections **(Reference: Specification SP-1302-52-094, paragraph 4.1).** The inspection specification identifies the Service Level I coatings to be inspected in the torus and vent system and requires performing general visual inspections **(Reference: Specification SP-1302-52-120, paragraph 4.2).** The inspection specifications identify the Service Level II coatings to be inspected in the area of the sandbed region and allow for either remote or direct visual examination methods **(Reference: Specification IS-328227-004, paragraph 3.1.2.2; Specification SP-1302-32-035, paragraph 4.1).**

d) After a walk-through, or during the general visual inspection, thorough visual inspections are carried out on previously designated areas and on areas noted as deficient during the walk-through. The scope of the inspections may also be expanded as a result of the initial inspections **(Reference: ER-AA-330-008, paragraph 4.9.1; Specification SP-1302-32-035 paragraphs 4.1.1 and 4.1.2).**

e) Inspection requirements include a thorough visual inspection of Service Level I coatings near the Emergency Core Cooling System (ECCS) suction strainers and visual examination of the suction strainers for any sign of blockage **(Reference: Specification SP-1302-52-120, paragraph 4.2).** Service Level I inspections are documented in a written report **(Reference: Procedure ER-AA-330-008, paragraph 4.14.1)** which is maintained in the Site Coating Coordinator's Coatings Program Notebook along with initial baseline information, Level I DBA qualification test reports, log of unqualified coatings, inspection plans and schedules, all licensing commitments, Generic Letter 98-04 response, and documentation of personnel qualifications **(Reference: ER-AA-330-008, paragraph 4.3.2).** An inventory list of tools, gauges, and instruments available for use during inspections is maintained, as applicable to the coatings being inspected **(Reference: ER-AA-330-008, paragraph 4.13.4)** and may include such items as flashlights, marker pens, mirrors, measuring tapes, magnifiers, binoculars, remote video equipment, etc.

<u>Exceptions to NUREG-1801, Element 4:</u>

None.

<u>Enhancements to NUREG-1801, Element 4:</u>

The inspection of Service Level I and Service Level II protective coatings that are credited for mitigating corrosion on interior surfaces of the Torus shell and vent system, and, on exterior surfaces of the Drywell shell in the area of the sandbed region, will be consistent with ASME Section XI, Subsection IWE requirements.

<u>Comparison and Evaluation Conclusion:</u>

This element is consistent with NUREG-1801, Element 4, Detection of Aging Effects with enhancement as discussed above.

3.4 Monitoring and Trending

NUREG-1801:

ASTM D 5163-05 identifies monitoring and trending activities in subparagraph 7.2, which specifies a pre-inspection review of the previous two monitoring reports, and in subparagraph 11.1.2, which specifies that the inspection report should prioritize repair areas as either needing repair during the same outage or postponed to future outages, but under surveillance in the interim period.

Oyster Creek:

Oyster Creek was not originally committed to Regulatory Guide 1.54 because the plant was licensed prior to the issuance of this Regulatory Guide in 1974. Currently, Oyster Creek is committed to a modified version of this Regulatory Guide, as described in the Oyster Creek response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10. Oyster Creek's response to GL 98-04 satisfies the requirements for an acceptable coatings maintenance aging management program (AMP) for license renewal as identified in the "Program Description" paragraph of NUREG-1801 Chapter XI program XI.S8, Protective Coating Monitoring and Maintenance Program. The Oyster Creek program for monitoring and maintaining Service Level I coatings inside containment is implemented through specification of appropriate technical and quality requirements of RG 1.54, Rev. 0 and American National Standards Institute (ANSI) N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities" and N101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities". The guidance provided in Electric Power Research Institute (EPRI) Technical Report TR-109937, "Guidelines on Nuclear Safety-Related Coating" has been evaluated and improvements have been implemented to the program as appropriate **(Reference: Exelon Quality Assurance Topical Report (QATR) NO-AA-10, Appendix C, Paragraph 1.3.2.6; Letter H. N. Pastis (NRC) to M. B. Roche (GPU Nuclear) dated January 19, 2000, "Completion of Licensing Action for Generic Letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment," dated July 14, 1998; Oyster Creek Nuclear Generating Station (TAC NO. MA4077)"; Letter No. 1940-98-20665 dated November 11, 1998, "Response to Generic Letter 98-04 dated July 14, 1998").**

The Site Coating Coordinator reviews the surveillance and inspection results from at least two previous outages **(Reference: Procedure ER-AA-330-008, paragraph 3.6)**. The Site Coating Coordinator also dispositions all recordable indications detected in accordance with applicable procedures and determines the need for repairs and changes to the outage coating inspection work scope based on this evaluation **(Reference: Procedure ER-AA-330-008, paragraph 3.6).**

Exceptions to NUREG-1801, Element 5:

None.

Enhancements to NUREG-1801, Element 5:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 5, Monitoring and Trending.

3.5 Acceptance Criteria

NUREG-1801:

a) *ASTM D 5163-05, subparagraphs 10.2.1 through 10.2.6, 10.3 and 10.4, contain one acceptable method for characterization, documentation, and testing of defective or deficient coating surfaces. Additional ASTM and other recognized test methods are available for use in characterizing the severity of observed defects and deficiencies. The evaluation covers blistering, cracking, flaking, peeling, delamination, and rusting.*

b) *ASTM D 5163-05, paragraph 12, addresses evaluation. It specifies that the inspection report is to be evaluated by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, including an analysis of reasons or suspected reasons for failure. Repair work is prioritized as major or minor defective areas. A recommended corrective action plan is required for major defective areas, so that these areas can be repaired during the same outage, if appropriate.*

Oyster Creek:

Oyster Creek was not originally committed to Regulatory Guide 1.54 because the plant was licensed prior to the issuance of this

Regulatory Guide in 1974. Currently, Oyster Creek is committed to a modified version of this Regulatory Guide, as described in the Oyster Creek response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10. Oyster Creek's response to GL 98-04 satisfies the requirements for an acceptable coatings maintenance aging management program (AMP) for license renewal as identified in the "Program Description" paragraph of NUREG-1801 Chapter XI program XI.S8, Protective Coating Monitoring and Maintenance Program. The Oyster Creek program for monitoring and maintaining Service Level I coatings inside containment is implemented through specification of appropriate technical and quality requirements of RG 1.54, Rev. 0 and American National Standards Institute (ANSI) N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities" and N101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities". The guidance provided in Electric Power Research Institute (EPRI) Technical Report TR-109937, "Guidelines on Nuclear Safety-Related Coating" has been evaluated and improvements have been implemented to the program as appropriate **(Reference: Exelon Quality Assurance Topical Report (QATR) NO-AA-10, Appendix C, Paragraph 1.3.2.6; Letter H. N. Pastis (NRC) to M. B. Roche (GPU Nuclear) dated January 19, 2000, "Completion of Licensing Action for Generic Letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment," dated July 14, 1998; Oyster Creek Nuclear Generating Station (TAC NO. MA4077)"; Letter No. 1940-98-20665 dated November 11, 1998, "Response to Generic Letter 98-04 dated July 14, 1998")**.

a) For in-process coating application inspections, the Site Coating Coordinator establishes acceptance criteria specific to the application **(Reference: Procedure ER-AA-330-008, paragraph 4.12.1.1)**. General acceptance criteria may also be used in conjunction with the Manufacturer's Product Data Sheet and/or the Coating Data Sheet (if one exists) for the specific application to evaluate the acceptability of defective coating, and, to prioritize repairs **(Reference: Procedure ER-AA-330-008, paragraph 4.12.1.2)**

   For Service Level I coating inspections inside the containment, guidance is provided in the inspection specifications for the identification of defects including blistering, cracking, flaking, peeling, delamination, and rusting. When appropriate, specific requirements for reporting defects are provided, such as, the reporting of blistering in accordance with ASTM D-714, "Standard Method of Evaluating Degree of Blistering of Paints." **(Reference: Specification SP-1302-52-120, paragraphs 4.2.1 and 4.2.4; Specification SP-1302-52-094, paragraphs 3.1, 4.1, and 4.3.1.1)**. The Site Coating Coordinator dispositions all recordable indications detected in accordance with applicable procedures **(Reference: Procedure ER-AA-330-008, paragraph 3.6).**

For Service Level II protective coating on the external drywell shell in the area of the sandbed region, guidance is provided in the inspection specification for the identification of defects **(Reference: Specification IS-328227-004, paragraph 3.1.3.3 and Exhibit 4)**. The Site Coating Coordinator dispositions all recordable indications detected in accordance with applicable procedures **(Reference: Specification IS-328227-004 paragraph 1.2 and Exhibit 4).**

b) The inspection report is evaluated by the Site Coating Coordinator who dispositions any recordable indications detected in accordance with applicable procedures. The Site Coating Coordinator also determines future surveillance and repair requirements, analyzes coating failures and develops corrective action plans based on the severity of the defects, and reviews and approves outage inspection work scope **(Reference: Procedure ER-AA-330-008, paragraph 3.6; Specification IS-328227-004 paragraph 1.2 and Exhibit 4).**

<u>Exceptions to NUREG-1801, Element 6:</u>

None.

<u>Enhancements to NUREG-1801, Element 6:</u>

The inspection of Service Level I and Service Level II protective coatings that are credited for mitigating corrosion on interior surfaces of the Torus shell and vent system, and, on exterior surfaces of the Drywell shell in the area of the sandbed region, will be consistent with ASME Section XI, Subsection IWE requirements.

<u>Comparison and Evaluation Conclusion:</u>

This element is consistent with NUREG-1801, Element 6, Acceptance Criteria with enhancement as discussed above.

3.6 Corrective Actions

NUREG-1801:

As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

Oyster Creek:

Evaluations are performed for test or inspection results that do not satisfy established criteria and an Issue Report (IR) is initiated to document the concern in accordance with Oyster Creek 10 CFR Part 50, Appendix B corrective action program. The 10 CFR Part 50, Appendix B corrective action program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined and an action plan is developed to preclude repetition.

Exceptions to NUREG-1801, Element 7:

None.

Enhancements to NUREG-1801, Element 7:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 7, Corrective Actions.

3.7 Confirmation Process

NUREG-1801:

As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

Oyster Creek:

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

Exceptions to NUREG-1801, Element 8:

None.

Enhancements to NUREG-1801, Element 8:

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 8, Confirmation Process.

3.8 Administrative Controls

NUREG-1801:

As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

Oyster Creek:

See Item 8, above.

Exceptions to NUREG-1801, Element 9:

None.

Enhancements to NUREG-1801, Element 9

None.

Comparison and Evaluation Conclusion:

This element is consistent with NUREG-1801, Element 9, Administrative Controls.

3.9 Operating Experience

NUREG-1801:

NRC Generic Letter 98-04 describes industry experience pertaining to coatings degradation inside containment and the consequential clogging of sump strainers. RG 1.54, Rev. 1, was issued in July 2000. Monitoring and maintenance of Service Level I coatings conducted in accordance with Regulatory Position C4 is expected to be an effective program for managing degradation of Service

Level I coatings, and consequently an effective means to manage loss of material due to corrosion of carbon steel structural elements inside containment.

Oyster Creek:

Oyster Creek was not originally committed to Regulatory Guide 1.54 because the plant was licensed prior to the issuance of this Regulatory Guide in 1974. Currently, Oyster Creek is committed to a modified version of this Regulatory Guide, as described in the Oyster Creek response to GL 98-04, and, as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10. Oyster Creek's response to GL 98-04 satisfies the requirements for an acceptable coatings maintenance aging management program (AMP) for license renewal as identified in the "Program Description" paragraph of NUREG-1801 Chapter XI program XI.S8, Protective Coating Monitoring and Maintenance Program. The Oyster Creek program for monitoring and maintaining Service Level I coatings inside containment is implemented through specification of appropriate technical and quality requirements of RG 1.54, Rev. 0 and American National Standards Institute (ANSI) N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities" and N101.4, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities". The guidance provided in Electric Power Research Institute (EPRI) Technical Report TR-109937, "Guidelines on Nuclear Safety-Related Coating" has been evaluated and improvements have been implemented to the program as appropriate. The experience at Oyster Creek with the Protective Coating Monitoring and Maintenance Program aging management program shows that the program is effective in managing Service Level I protective coatings inside the containment, and, in managing Service Level II coatings on the external drywell shell in the area of the sandbed region.

Operating experience, both internal and external, is used in two ways at Oyster Creek to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants from occurring at Oyster Creek. The first way in which operating experience is used is through the Oyster Creek Operating Experience process. 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 both 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.), General Electric documents (e.g., RCSILs, SILs, TILs, etc.), and other documents (e.g., 10CFR 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.

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that the Protective Coating Monitoring and Maintenance Program aging management program adequately manages Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sandbed region. The following examples of operating experience provide objective evidence that the Protective Coating Monitoring and Maintenance Program aging management program is effective in assuring that intended function(s) will be maintained consistent with the CLB for the period of extended operation:

Coating History and Operating Experience

Drywell: (Reference 4.3.6) The Oyster Creek drywell interior surfaces above the concrete floor, including jet deflectors, and the exterior of the drywell above the water seal support bracket were originally coated with one coat of Carboline Carbo-Zinc 11 paint. The interior surface of the drywell below el. 12'-3" and the exterior surface of the drywell in direct contact with final support concrete was not painted.

The potential for corrosion of the drywell vessel was first recognized when water was noticed coming from the sand bed drains in 1980. Corrosion was later confirmed by ultrasonic thickness (UT) measurements taken in 1986 during the 11R refueling outage. During the 12R refueling outage in 1988, the first extensive corrective action, installation of a cathodic protection system, was taken. This proved to be ineffective. The system was removed during the 14R refueling outage in 1992.

The upper regions of the vessel, above the sand bed, were handled separately from the sand bed region because of the significant difference in corrosion rate and physical difference in design. Corrective action for the upper vessel involved providing a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. Amendment 165 to the Oyster Creek Technical Specification reduced the drywell design pressure from 62 psig to 44 psig. The new design pressure coupled with measures to prevent water intrusion into the gap between the vessel and the concrete will allow the upper portion of the vessel to meet ASME code for the remainder life of the plant.

In the sand bed region laboratory testing determined the corrosion mechanism to be galvanic. The high rate of corrosion in this region required prompt corrective action of a physical nature. Corrective action was defined as; (1) removal of sand to break up the galvanic cell, (2) removal of the corrosion product from the vessel and (3) application of a protective coating. Keeping the vessel dry was also identified as a requirement even though it would be less of a concern in this region once the coating was applied. The work was initiated during the 12R refueling outage in 1988 by removing sheet metal from around the vent headers to provide access to the sand bed from the Torus room. During operating cycle 13 some sand was removed and access holes were cut into the sand bed region through the shield wall. The work was finished during the 14R refueling outage in 1992.

After sand removal, the concrete floor was found to be unfinished with improper provisions for water drainage. Corrective actions taken in this region during the 14R refueling outage in 1992 included; (1) cleaning of loose rust from the drywell shell, followed by application of epoxy coating and (2) removing the loose debris from the concrete floor followed by rebuilding and reshaping the floor with epoxy to allow drainage of any water that may leak into the region.

During 14R, UT measurements were taken from the outside surface of the drywell vessel in the sand bed region. Measurements were taken in each of the ten sand bed bays. The results of this inspection and the structural evaluation of the "as found" condition of the vessel are contained in TDR No. 1108, "Summary Report of Corrective Action Taken from Operating Cycle 12 Through 14R", Revision 0 (Reference 4.3.5). As documented in TDR No. 1108, the vessel was evaluated to conform to ASME code requirements given the deteriorated thickness condition. In general these measurements verified projections that had been made based on measurements taken from inside the drywell. Several areas were thinner than projected. In all cases these areas were found to meet ASME code requirements after structural analysis.

The coated surfaces of the former sand bed region have been subsequently inspected during refueling outages in 1994, 1996, 2000, and 2004 as documented in DCR 05-00023-00 Attachment 1, Page 12, paragraph 7.8.1.3.1 (Reference 4.3.6). The inspections showed no coating failure or signs of deterioration. It is therefore concluded that the cleaning, floor refurbishing and coating effort completed in 14R has been effective in mitigating corrosion in the sand bed area. Since this was accomplished while the vessel thickness was sufficient to satisfy ASME code requirements, drywell vessel corrosion in the sand bed region is no longer a limiting factor in plant operation, however, inspections are conducted to ensure that the coating remains effective. In addition, UT measurements are also taken from inside the drywell. The frequency and extent of the coating inspections and UT thickness measurements are as follows:

1. For the upper elevations, UT measurements are taken every second refueling outage. After each inspection, a determination will be made if additional inspection is to be performed. Although protective coating is not credited for corrosion mitigation in these areas, the coating is inspected to ensure its integrity for the purpose of maintaining ECCS suction strainer debris loading assumptions.
2. For the sandbed region, visual inspection of the coating is performed every second refueling outage. After each inspection, a determination will be made if additional inspection is to be performed.
3. For water leakage not associated with refueling activities, an investigation will be made as to the source of the leakage. Oyster Creek will take corrective actions, evaluate the impact of the leakage and, if necessary, perform an additional drywell inspection about three months after the discovery of the water leakage.

Calculation Number C-1302-187-E310-037, "Statistical Analysis of Drywell Vessel Thickness Data", Revision 2 (Reference 4.3.7) provides the evaluation of the latest drywell UT inspections performed by IS-328227-004 (through November 2004).

Oyster Creek has committed to notify the NRC prior to implementing any changes to the drywell thickness measurement inspection program.

The above discussion on Drywell coating history and operating experience provides objective evidence that previous corrective actions have been effective in mitigating corrosion in the sandbed region and that the Protective Coating Monitoring and Maintenance Program aging management program is effectively implemented to ensure that the intended function of systems, structures, and components within the scope of license renewal will be maintained during the extended period of operation.

Torus and Vent Systems: (Reference 4.3.8) The Oyster Creek torus and vent system were originally coated with one coat of Carboline Carbo-Zinc 11 paint. In 1983, the Torus interior surfaces, the interior of the Vent System up to the drywell and all external surfaces of the Vent System were grit blasted to SSPC-10 or SSPC-5 at 1 1/2 - 3 mils profile.

Pitted surfaces of immersed Torus shell were repaired by welding. Rough areas of Torus shell were blended by grinding. Mobil 46-X-16 Epoxy Filler was applied to selected pitted areas of the Torus immersed shell portion prior to coating. Surfaces in the Vent System thinned by corrosion were repaired by welding.

The immersed bottom half of the Torus shell, the interior of the downcomer and the entire interior surfaces of the Vent System were given 3 coats of Mobil 78 Hi-Build Epoxy (DFT-16 mils). The vapor phase upper half of the Torus shell, exterior of the Vent Header and vent lines portions inside the Torus were given two coats of Mobil 78-Hi Build epoxy (DFT-10 mils).

Following coating application, the entire Torus interior was heat cured at 108°F for 48 hours. Demineralized water was put back in the Torus. Subsequent to this coating application, minor coating repairs have been performed using BRUTEM-15 (UT-15).

De-sludging, inspection, and repair of the interior coating of the torus shell and vent system located above and below the water line is performed during refueling outages in accordance with Specification SP-1302-52-120. Torus and vent header vapor space Service Level I coating inspections performed in 2002 found the coating in these areas to be in good condition. Inspection of the immersed coating in the Torus identified blistering. The blistering occurred primarily in the shell invert but was also noted on the upper shell near the water line. The majority of the blisters remained intact and continued to protect the base metal. However, several blistered areas included pitting damage where the blisters were fractured. A qualitative assessment of the identified pits was performed and concluded that the measured pit depths were significantly less than the established acceptance criteria. The fractured blisters were repaired to reestablish the protective coating barrier.

The above discussion on Torus and Vent System coating history and operating experience provides objective evidence that previous corrective actions have been effective in mitigating corrosion in the Torus and Vent System and that the Protective Coating Monitoring and Maintenance Program aging management program is effectively implemented to ensure that the intended function of systems, structures, and components within the scope of license renewal will be maintained during the extended period of operation.

Miscellaneous OE:

CAP No. O2000-1429 identified that a modification was to add approximately 28 square feet of hot dipped galvanized unistrut steel to the drywell. Specification SP-1302-06-009, "Specification for Application and Repair of Service Level I Coatings on Ferrous Metal Surfaces Oyster Creek Nuclear Generating Station", Appendix A for approved coatings inside the primary containment, does not include galvanized coating as an approved coating. An evaluation was performed by engineering and it was concluded that a) DBA conditions will not adversely affect galvanized surfaces or the functioning of safety systems, b) hot dipped galvanized surfaces are not required to be DBA tested by any code, standard, or regulation, and c) the addition of this galvanized unistrut steel to the drywell was acceptable. This example provides objective evidence that the addition of unqualified coatings to the primary containment are evaluated for impact on safety related systems and structures.

CAP No. O2003-2454 identified that the replacement motor for the "A" recirculation motor was top coated with a non-DBA qualified coating on the motor housing, end bells, and stator. Engineering analysis concluded that the unqualified coating would minimally impact the strainer debris loading following a postulated LOCA and that any additional head loss created by the additional unqualified coating was negligible. This example provides objective evidence that the addition of unqualified coatings to the primary containment is evaluated for impact on safety related systems and structures.

The operating experience of the Protective Coating Monitoring and Maintenance Program 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 Protective Coating Monitoring and Maintenance Program aging management program will effectively manage Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sandbed region.

3.10 Conclusion

The Oyster Creek Protective Coating Monitoring and Maintenance Program aging management program provides for aging management of Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sandbed region. The Protective Coating Monitoring and Maintenance Program aging management program is credited for managing the systems, components, materials, and environments listed in Table 5.2. The Oyster Creek Protective Coating Monitoring and Maintenance Program aging management program's elements have been evaluated against NUREG-1801 in Section 3.0. There are no program exceptions as identified in Section 2.3. Program enhancements are identified in Section 2.4. The implementing documents and commitment numbers for this aging management program are listed in Table 5.1. The relevant operating experience has been reviewed and a demonstration of program effectiveness is provided in Section 3.10.

Based on the above, the continued implementation of the Oyster Creek Protective Coating Monitoring and Maintenance Program aging management program provides reasonable assurance that Service Level I coatings inside the primary containment and Service Level II coatings for the external drywell shell in the area of the sandbed region 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.

4.0 REFERENCES

4.1 Generic to Aging Management Programs

4.1.1 10 CFR 50, Appendix B, *Quality Assurance Criteria for*

Nuclear Power Plants and Fuel Reprocessing Plants

4.1.2 10 CFR 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*

4.1.3 NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,* Revision 1, dated September 2005

4.1.4 NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*, Revision 1, dated September 2005

4.2 Industry Standards

4.2.1 Electric Power Research Institute (EPRI) Technical Report TR-109937, "Guidelines on Nuclear Safety-Related Coating"

4.3 Oyster Creek Program References

4.3.1 Exelon Quality Assurance Topical Report (QATR) NO-AA-10, Appendix C, Paragraph 1.3.2.6

4.3.2 Letter H. N. Pastis (NRC) to M. B. Roche (GPU Nuclear) dated January 19, 2000, "Completion of Licensing Action for Generic Letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment," dated July 14, 1998; Oyster Creek Nuclear Generating Station (TAC NO. MA4077)"

4.3.3 Letter No. 1940-98-20665 dated November 11, 1998, "Response to Generic Letter 98-04 dated July 14, 1998"

4.3.4 Calculation Number C-1302-241-E610-081, "Suction Strainer Debris Generation and Transport", Revision 2

4.3.5 TDR No. 1108, "Summary Report of Corrective Action Taken from Operating Cycle 12 through 14R," Revision 0

4.3.6 DCR OC 05-00023-00, "Revision of C-1302-187-E310-037 and FSAR Chapter 3.8.2.8"

4.3.7 Calculation C-1302-187-E310-037, "Statistical Analysis of Drywell Vessel Thickness Data Through September 2000" (updated through November 2004), Revision 2

4.3.8 Oyster Creek UFSAR Section 3.8.2.6.2

5.0 TABLES

5.1 Aging Management Program Implementing Documents

Procedure Number	Procedure Title	Commitment No.	Status
ER-AA-330-008	Exelon Service Level I, and Safety Related (Service Level III) Protective Coatings	00330592.33.01	ACC/ASG
CC-AA-205	Control of Undocumented/Unqualified Coatings Inside the Containment	00330592.33.02	ACC/ASG
SP-1302-06-009	Specification for Application and Repair of Service Level I Coatings on Ferrous Metal Surfaces Oyster Creek Nuclear Generating Station	00330592.33.03	ACC/ASG
SP-1302-52-094	Specification for Drywell Shell Coating Touch-Up	00330592.33.05	ACC/ASG
SP-1302-52-120	Specification for Inspection and Localized Repair of the Torus and Vent System Coating	00330592.33.06	ACC/ASG
IS-328227-004	Installation Specification for Oyster Creek Functional Requirements for Drywell Containment Vessel Thickness Examination	00330592.33.08	ACC/ASG
SP-9000-06-003	Specification for Application and Repair of Service Level II and Balance of Plant Coatings	00330592.33.07	ACC/ASG

SP-1302-32-035	Specification for Inspection and Minor Repair of Coating on Concrete & Drywell Shell Surfaces in the Sandbed Region	00330592.33.04	ACC/ASG
(New PM)	Inspect Drywell Exterior Service Level II Coating in the Region of the Sandbed	00330592.33.12	ACC/ASG
(New PM)	Inspect Interior Vent System Service Level I Coating	00330592.33.11	ACC/ASG
(New PM)	Inspect Interior Drywell Vessel Service Level I Coating	00330592.33.09	ACC/ASG
(New PM)	Inspect Interior Torus Service Level I Coating	00330592.33.10	ACC/ASG

5.2 Aging Management Review Results

SSC Name	Structure and/or Component	Material	Environment	Aging Effect
Primary Containment	Access Hatch Covers	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Downcomers	Carbon and low alloy steel	Containment Atmosphere	Loss of Material
Primary Containment	Downcomers	Carbon and low alloy steel	Treated Water < 140F	Loss of Material
Primary Containment	Drywell Penetration Sleeves	Carbon and low alloy steel, Dissimilar Metal Welds	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Penetration Sleeves	Carbon and low alloy steel, Dissimilar Metal Welds	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Drywell Shell	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Shell	Carbon and low alloy steel	Indoor Air (External)	Loss of Material
Primary Containment	Drywell Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Personnel Airlock/Equipment Hatch	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Suppression Chamber Penetrations	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Suppression Chamber Ring Girders	Carbon and low alloy steel	Containment Atmosphere (External)	Loss of Material
Primary Containment	Suppression Chamber Ring Girders	Carbon and low alloy steel	Treated Water < 140F (External)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material

Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Suppression Chamber Shell	Carbon and low alloy steel	Treated Water <140F (Internal)	Loss of Material
Primary Containment	Vent line, and Vent Header	Carbon and low alloy steel	Containment Atmosphere (Internal)	Loss of Material
Primary Containment	Vent line, and Vent Header	Carbon and low alloy steel	Indoor Air (External)	Loss of Material

6.0 ATTACHMENTS

6.1 LRA Appendix A

6.2 LRA Appendix B