July 20, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
AMERGEN ENERGY COMPANY, LLC	)	Docket No. 50-219-LR
	)	
(Oyster Creek Nuclear Generating Station)	)	

NRC STAFF INITIAL STATEMENT OF POSITION ON THE DRYWELL CONTENTION

INTRODUCTION

Pursuant to 10 C.F.R. §§ 2.1207(a)(1) and 2.337(g)(2), the "Memorandum and Order (Prehearing Conference Call Summary, Case Management Directives, and Final Scheduling Order) (April 17, 2007) (unpublished) ("April 17 Order"), at 4, the Staff of the U.S. Nuclear Regulatory Commission ("Staff") submits its initial written statements of positions and written testimony with supporting affidavits on Citizens'[1] admitted contention. Appended to this filing is the "NRC Staff Testimony of Hansraj G. Ashar, James A. Davis, Mark Hartzman, and Timothy L. O'Hara Concerning Drywell Contention" (July 20, 2007) ("Testimony") and Staff's Exhibits 1 and 2: "SER Excerpts" and "Subsection IWE Excerpts (Parts of -1000, -2000, -3000)." For the reasons set forth below and in the testimony filed herewith, the Staff submits that a careful evaluation of Citizens' Drywell Contention demonstrates that Citizen's challenge to the AmerGen Energy Company, LLC ("AmerGen") application for renewal of the Oyster Creek operating license cannot be sustained.

[1] The six organizations are Nuclear Information and Resource Service, Jersey Shore Nuclear Watch, Inc., Grandmothers, Mothers, and More for Energy Safety, New Jersey Public Interest Research Group, New Jersey Sierra Club, and New Jersey Environmental Federation.

BACKGROUND

This proceeding concerns AmerGen's application to renew Oyster Creek's operating license for 20 years past the April 9, 2009 expiration date. On November 14, 2005, Citizens filed a timely request for hearing concerning AmerGen's application to renew the Oyster Creek operating license for 20 years past the April 9, 2009 expiration date. On February 27, 2006, the Atomic Safety and Licensing Board ("Board") granted Citizens' intervention petition, admitting a contention that alleged that the license renewal application ("LRA")[2] was deficient due to the failure to include periodic ultrasonic test (UT) measurements of the sand bed region of the drywell liner in the aging management program, and rejecting Citizens' attempt in its reply to expand the contention. LBP-06-07, 63 NRC 188, 211-217 (2006).[3] On February 7, 2006, the Board rejected Citizens' February 7, 2006, attempt to raise contentions challenging, among other things, the adequacy of monitoring of thickness in inaccessible areas of the drywell liner. LBP-06-11, 63 NRC 391, 393-95, *review den'd*, CLI-06-24, 64 NRC 111 (2006).

On June 6, 2006, the Board ruled that Citizens' contention of omission was rendered moot by AmerGen's April 4, 2006, commitment[4] to perform periodic UT measurements in the sand bed region of the drywell (*i.e.*, prior to entering the period of extended operation and every ten years thereafter), but gave Citizens the opportunity to file a new contention challenging AmerGen's new periodic UT program for the sand bed region. LBP-06-16, 63 NRC 737, 742-45

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[2] Letter from C. N. Swenson, AmerGen, to NRC (July 22, 2005) (ML052080172).

[3] The admitted contention alleged that "AmerGen's corrosion management program . . . will not enable AmerGen to determine the amount of corrosion in that region and thereby maintain the safety margins during the term of the extended license." LBP-06-07, 63 NRC at 217. Prior to the admission of the contention, AmerGen committed to "perform a set of onetime thickness measurements . . . in the 'sand bed region' . . . at a sample of areas previously inspected (in the 1990s) and identified as having exhibited corrosion." Letter from C. N. Swenson, AmerGen, to NRC (Dec. 9, 2005) (ML053490219), at 3.

[4] Letter from Michael P. Gallagher, AmerGen, to NRC (Apr. 4, 2006) (ML060970288).

(2006). Citizens' filing was to be limited to AmerGen's new UT program for that region as reflected in its April 4 commitment and was to address the remaining factors in 10 C.F.R. § 2.309(f)(2), as well as the admissibility factors in 10 C.F.R. § 2.309(f)(1). *Id.* at 744-45.

Citizens subsequently submitted a contention based on the April 4 commitment, got permission to file a supplement limited to AmerGen's UT program as reflected in a June 20, 2006 commitment and new information in that commitment,[5] and filed a supplemental petition. *See* [Citizens'] Motion for Leave to Supplement the Petition (June 23, 2006) ("June 23 Petition"); Order (Granting NIRS's Motion for Leave to Submit a Supplement to its Petition (July 5, 2006) (unpublished); "Supplement to Petition to Add a New Contention" (July 25, 2006) ("Supplement").[6] On October 10, 2006, the Board admitted one of seven challenges[7] raised by Citizens as the following contention:

> [I]n light of the uncertain corrosive environment and correlative uncertain corrosion rate in the sand bed region of the drywell shell, AmerGen's proposed plan to perform UT tests prior to the period of extended operations, two refueling outages later, and thereafter at an appropriate frequency not to exceed 10-year intervals is insufficient to maintain an adequate safety margin.

LBP-06-22, 64 NRC 229, 255-56 (2006). The Board noted that Citizens' argument was grounded upon the assumption that the corrosion rate in the sand bed region is unknown due to the uncertain corrosive environment. *See* 64 NRC at 240. The Board, *inter alia,* rejected as nontimely Citizens' challenge to the adequacy of monitoring the sand bed region for integrity of

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[5] Letter from Michael P. Gallagher, AmerGen, to NRC (June 20, 2006) (ML061740573).

[6] Appended to Citizens' June 23 Petition and the Supplement are memoranda from Rudolph Hausler, dated June 23 and July 25, 2007, respectively.

[7] Citizens challenged as inadequate AmerGen's (1) drywell thickness acceptance criteria, (2) scheduled UT monitoring frequency, (3) moisture and coating integrity monitoring, (4) response to wet conditions and coating failure, (5) scope of UT monitoring to systematically identify and sufficiently test degraded areas, (6) quality assurance for measurements, and (7) methods for analyzing UT results. *See* LBP-06-22, 64 NRC at 236.

the epoxy coating and for moisture as well as the challenge to the spatial scope of AmerGen's UT measurements and assertions that monitoring fails to systematically survey thin areas, and the challenge to AmerGen's drywell minimum thickness acceptance criteria (*i.e.*, 0.736 inches and 0.536 inches) used since 1992. *Id.* at 244-51, 237-240; *reconsideration den'd,* Memorandum and Order (Nov. 20, 2006) (unpublished).

On February 9, 2007, the Board denied Citizen's request[8] to admit two late contentions concerning (1) AmerGen's December 3, 2006 proposal[9] to conduct UT monitoring in the embedded region and (2) the inadequacy of AmerGen's proposed monitoring in the sand bed region from the outside. The Board ruled that the contentions were nontimely under 10 C.F.R. § 2.309(f)(2), and inadmissible under § 2.309(f)(1) since they failed to raise a genuine dispute regarding a material issue of law or fact. Memorandum and Order (Denying Citizens' Motion for Leave to Add Contentions and Motion to Add Contention) (unpublished), slip op. at 7, 15-16, 19.

In a Memorandum and Order, dated April 10, 2007 (unpublished), the Board also rejected, as unjustifiably late, Citizens' request to add a late contention alleging that UT acceptance criteria for the drywell shell should be increased from 0.536 and 0.736 inches to 0.618 and 0.844 inches, respectively.

On March 30, 2007, AmerGen Energy Company, LLC (AmerGen) filed a "Motion for Summary Disposition of Citizens' Drywell Contention" (SD Motion) and attached (1) two

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[8] Motion for Leave to Add Contentions and Motions to Add Contentions (Dec. 20, 2006). Appended to this filing was the December 3 Supplement (Exh. ANC 1), AmerGen's Advisory Committee on Reactor Safeguards Information Package (Exh. ANC 2), an Oyster Creek shift turnover note for October 21-22, 2006 (Exh. ANC 3), a Memorandum of Dr. Rudolph Hausler (Dec. 19, 2006) (Exh. ANC 4) ("Sixth Hausler Memo"), an Oyster Creek Action Request (Oct. 25, 2006) (Exh. ANC 5), and a Letter from Richard Conte, NRC, to Richard Webster (Nov. 9, 2006) (Exh. ANC 6).

[9] Letter from Michael P. Gallagher to NRC (Dec. 3, 2006) (enclosing Post-2006 Refueling Outage Information) ("December 3 Supplement") (ML063390664). Corrections to this letter were submitted on December 15, 2006 (ML063530042).

drawings of the drywell (Exhibits 1 and 2); (2) a Letter from AmerGen to NRC, dated February 15, 2007 (ML070520252), documenting commitments made at a February 1, 2007 Advisory Committee on Reactor Safeguards ("ACRS") meeting, including a commitment to perform full scope of drywell sand bed region inspections every other refueling outage; (3) the Affidavit of Peter Tamburro, dated March 26, 2007 ("Tamburro Affidavit"); (4) the Affidavit of Barry Gordon, dated March 26, 2007 ("Gordon Affidavit"); and (5) the Affidavit of Jon R. Cavallo, dated March 26, 2007 ("Cavallo Affidavit"). The Staff filed a response supporting the motion and Citizens opposed the motion. *See* NRC Staff Response to AmerGen's Motion for Summary Disposition (Apr. 26, 2007); Citizens' Answer Opposing AmerGen's Motion for Summary Disposition (Apr. 26, 2007).

The Board denied the motion for summary disposition, finding it was unable to conclude as a matter of law that AmerGen's UT monitoring plan is sufficient to ensure adequate safety margins during the period of extended operation. Memorandum and Order (Denying AmerGen's Motion for Summary Disposition) (June 19, 2007) (unpublished), at 12. The Board noted that Citizens had asserted that uncertainty surrounds all of the facts underlying AmerGen's current approach to taking UT measurements once every four years in the sand bed region and that disputes exist regarding (1) the remaining safety margins, (2) the potential for corrosion under the epoxy coating due to defect in and deterioration of the coating that is "past its useful life" and (3) future corrosion rates. *Id.* (citing Hausler Memorandum at 1-12).

The Board indicated that it viewed the relevant factual issues for litigation as:

> (1) the amount by which the remaining thickness of the shell exceeds the established criteria in the sand bed region; (2) existence *vel non* of a corrosive environment, taking into account whether sources of water have been eliminated as well as whether, regardless of the potential existence of water, a corrosive environment can exist in the sand bed region after the sand was removed and the protective coating applied, particularly considering that the sand is no longer there to hold water in the previously corroded areas of the shell; and (3) the corrosion rate – including the uncertainties related to its determination [e.g., limited accuracy of the measurement method used, use of a limited number of

data points, and the method use to analyze and interpret the data].

SD Order at 7. The Board indicated that evidence on uncertainties may include both the measurement technique and the interpretation of data and that the Board's consideration of uncertainties will determine how much actual values of thickness can reasonably be expected to differ from the measured values. *Id.* at n. 10. The Board further indicated that establishment of such facts would determine "how rapidly the thickness is approaching the acceptance criteria and, thus the adequacy of the frequency of UT measurements AmerGen proposed to take during the period of extended operation." *Id.* at 7.[10]

In addition, the Board indicated that Citizens "may not challenge the derivation or validity of the established acceptance criteria or the methodology for analyzing UT results," but are not precluded from arguing that application of these items is inconsistent with past practice. *Id.* at 8. The Board also noted that it expected the parties to address whether the "bathtub ring" of corrosion in the sand bed region may lead to a buckling failure between scheduled UT measurements and whether the existing corrosion in sand bed region, if exacerbated by future corrosion, would render "the shell susceptible to buckling failure for which the buckling acceptance criteria [were] developed, and if not, what criteria (such as a leakage criteria) should apply." *Id.* at 9 n.11.

On July 11, 2007, the Board issued Memorandum and Order Clarifying Memorandum and Order Denying AmerGen's Motion for Summary Disposition (unpublished), in response to a joint motion for clarification filed by the Party on June 29, 2007. Therein the Board stated that

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[10] The Board indicated that listed factual issues may also require resolution of ancillary issues such as whether the monitoring frequency is sufficient to ensure maintenance of an adequate safety margin under the protective epoxy coating in the sand bed region due to "'uncertainty regarding the existence . . . of a corrosive environment in th[at] region and the correlative uncertainty regarding corrosion rates in that region'" as well as the possibility that "'corrosion may occur under epoxy coating in the absence of visual deterioration due to visible . . . pinholes.'" SD Order at 7-8 (citing LBP-06-22, 64 NRC at 240, 242).

“Citizens may not challenge any aspect of AmerGen’s UT monitoring program that applies prior to the period of extended operation (i.e. prior to 2009),” but they may use information resulting from Oyster Creek’s 2006 UT measurements. Slip op. at 2. The Board clarified that “established” technique for analyzing UT data and calculating the rate of corrosion refers to “the methodology approved by the NRC Staff and relied upon in the Safety Evaluation Report.” *Id.* The Board admonished Citizens’ not to attack AmerGen’s “established” technique, but stated that Citizens may seek to demonstrate that AmerGen has not consistently applied its established technique. *Id.*

For the reasons set forth below, the contention lacks merit.

<u>DISCUSSION</u>

I. <u>Legal and Regulatory Requirements</u>

The scope of license renewal proceedings is limited. The Commission’s “[l]icense renewal reviews are not intended to ‘duplicate the Commission’s ongoing review of operating reactors.’” *Florida Power & Light Co.* (Turkey Point Nuclear Generating Plant, Units 3 & 4), CLI-01-17, 54 NRC 3, 7 (2001) (citing Final Rule, “Nuclear Power Plant License Renewal,” 56 Fed. Reg. 64,943, 64,946 (Dec. 13, 1991)). Therefore, the license renewal safety review process focuses on the “potential detrimental effects of aging that are not routinely addressed by ongoing regulatory oversight programs.” *Id*. Consequently, “10 C.F.R. Part 54 requires renewal applicants to demonstrate how their programs will be effective in managing the effects of aging during the period of extended operation.” *Id.* at 8 (citing 10 C.F.R. § 54.21(a)). Applicants are required to “identify any additional actions, i.e., maintenance, replacement of parts, etc., that will need to be taken to manage adequately the detrimental effects of aging.” *Id.* (citing Final Rule, “Nuclear Power Plant License Renewal: Revisions,” 60 Fed. Reg. 22,461, 22,479 (May 8, 1995)). The Commission has recognized that these “adverse aging effects generally are gradual and thus can be detected by programs that ensure sufficient inspections and testing." *Id.* (citing 60 Fed. Reg. at 22,475). License renewal proceedings are limited to a "review of the plant structures and components that will require an aging management review for the period of extended operation and the plant's systems, structures, and components that are subject to an evaluation of time-limited aging analyses." *Duke Energy Corp.* (McGuire Nuclear Station, Units 1 and 2; Catawba Nuclear Station, Units 1 and 2), CLI-01-20, 54 NRC 211, 212 (2001) (citing 10 C.F.R. §§ 54.21(a) and (c), 54.4; Nuclear Power Plant License Renewal: Revisions, Final Rule, 60 Fed. Reg. 22,461 (1995)).

The issue before the Board in this proceeding is "whether, in light of uncertainty regarding the existence *vel non* of a corrosive environment in the sand bed region and the correlative uncertainty regarding corrosion rates in that region, Amergen's UT monitoring plan is sufficient to ensure adequate safety margins." SD Order at 2. The adequacy of the Staff's review of AmerGen's application is not at issue. *See* Rules of Practice for Domestic Licensing Proceedings-Procedural Changes in the Hearing Process, Final Rule, 54 Fed Reg. 33168, 33171 (Aug. 11, 1989) (citing *Pacific Gas and Electric Co.* (Diablo Canyon Nuclear Power Plant, Units 1 and 2), ALAB-728, 17 NRC 777, 807, *review declined,* CLI-83-82, 18 NRC 1309 (1983)). The overall burden is on AmerGen to demonstrate that its UT monitoring program is adequate to manage the aging effects of corrosion on Oyster Creek's drywell so that the intended function of the drywell will be maintained during the period of extended operations. *See* 10 C.F.R. § 2.325. Citizens, however, must come forward with evidence that AmerGen's UT program is inadequate. *Louisiana Power & Light Co.* (Waterford Steam Electric Station, Unit 3), ALAB-732, 17 NRC 1076, 1093 (1983).

The Commissions' requirements with respect to the adequacy of Oyster Creek's program to monitor the condition of the drywell during the license renewal period are described in the testimony filed herein. Specifically, as set forth in the Staff's NUREG-1875, "Safety Evaluation Report Related to the License Renewal of Oyster Creek Generating Station" (Mar. 2007, Published Apr. 2007) ("SER"), the applicable legal standard for the Staff's approval of Oyster Creek's program is 10 C.F.R. § 54.21(a)(3), i.e. whether AmerGen has demonstrated "that the effects of aging [of the Oyster Creek drywell shell] will be adequately managed so that the intended function(s) [i.e., structural support and pressure boundary] will be maintained . . . for the period of extended operation.'" *Oyster Creek* LBP-06-22, 64 NRC at 241 (quoting 10 C.F.R. § 54.21(a)(3)). One way for a licensee to make the demonstration required by § 54.21(a)(3), is to commit to following the guidance provided by the Generic Aging Lessons Learned ("GALL") Report, NUREG-1801, Rev. 1. AmerGen claimed that its program for managing the effects of aging on the drywell shell is consistent, with an exception and enhancements contained in Commitments 27 and 33, with applicable provisions of GALL. *See* SER § 3.0.3.2.23. Therefore, the Staff reviewed Oyster Creek's program to determine consistency with GALL and, in addition, reviewed each exception or enhancement to determine whether it was acceptable and whether the program, as modified, would adequately manage the effect for which it was credited. *See* SER at 3-4 to 3-5.

II. Staff's Witnesses

The attached testimony presents the opinions of a panel of four highly qualified witnesses as follows: 1) Hansraj G. Ashar, a Senior Structural Engineer in the Division of Engineering, Office of Nuclear Reactor Regulation (NRR); 2) Dr. James A. Davis, a Senior Materials Engineer in the NRR Division of License Renewal; 3) Dr. Mark Hartzman, a Senior Mechanical Engineer in the NRR Division of Engineering; and 4) Timothy L. O'Hara, a Reactor Inspector in the Division of Reactor Safety, NRC Region I Office. Testimony at A1(a)-(d).

Mr. Ashar (a Structural Engineer) has reviewed plant license and license renewal applications, and has been involved in nuclear power plant standards development. *Id.* at A2(a). Mr. Ashar represents the NRC on committees for a number of organizations that develop standards related to nuclear power plant structures, namely, the American Society of

Mechanical Engineers (ASME), American Concrete Institute, and American Institute of Steel Construction. *Id.* Mr. Ashar was the lead technical coordinator for development of Chapter II of GALL related to the positions on PWR and BWR containments. *Id.* Mr. Ashar reviewed Section 4.7.2, "Time Limited Aging Analysis of Drywell Corrosion" in the Oyster Creek License Renewal Application and prepared Section 4.7.2 of the SER. *Id.* at A3(a). Mr. Ashar's testimony addresses the Staff's review of AmerGen's program to manage the aging effect of corrosion on Oyster Creek's drywell shell with respect to the Staff's conclusion that AmerGen's drywell monitoring program is sufficient to ensure that the drywell can perform its intended function during the proposed license renewal period. *Id.* at A4(a).

Dr. Davis (a Metallurgical Engineer) was a member of the license renewal safety audit team for Oyster Creek. *Id.* at A3(b). Dr. Davis reviewed portions of Oyster Creek's LRA, including numerous aging management programs. *Id.* Dr. Davis has worked on coating and corrosion control since 1968, and has worked on coatings issues at nuclear facilities for the past 16 years at the NRC. *Id.* at A2(b). Dr. Davis' testimony addresses Citizens' assertion that visual inspection of the epoxy coating is insufficient because corrosion may occur under the epoxy coating in the absence of visual indications. *Id.* at A4(b).

Dr. Hartzman (a Mechanical Engineer) is responsible for reviewing safety analyses of ASME Section III Class 1, 2, and 3, and non-ASME piping systems and components submitted by licensees in license amendment requests. *Id.* at A2(c). Dr. Hartzman represents the NRC at ASME Section III Code-writing working groups and reviews ASME Section III code cases for NRC endorsement. *Id.* In the connection with license renewal, Dr. Hartzman evaluates time limited aging analyses of ASME Section III metal components. *Id.* With respect to Oyster Creek's LRA, Dr. Hartzman reviewed the applicability of ASME Section Code Case N-284 to the buckling/stability analyses of the Oyster Creek drywell shell performed by General Electric and the Sandia National Laboratory. *Id.* at A3(c). Dr. Hartzman's testimony addresses the Staff's review of the buckling analysis for the drywell shell and the purpose of the ASME buckling criteria. *Id.* at A4(c).

Mr. O'Hara (a Reactor Inspector) participated in the License Renewal Aging Management Inspection conducted in March 2006 at Oyster Creek, reviewing Aging Management Programs: B.1.27, ASME Section XI, Subsection IWE Program; and B.1.33, Protective Coating Monitoring and Maintenance Program. *Id.* at A3(d). Mr. O'Hara participated in the NRC inspection of license renewal commitments regarding the drywell shell and torus conducted during Oyster Creek's 2006 outage. *Id.* Mr. O'Hara's testimony describes his observations of condition of the drywell in the sand bed region and the Staff's inspection findings concerning AmerGen's commitments related to license renewal and the drywell. *Id.* at A4(d).

III. <u>The Concerns Raised by the Contention Lack Merit</u>

The Staff's testimony presents its position that the concerns raised by Citizens' contention lack merit because AmerGen's UT monitoring frequency is sufficient to maintain an adequate safety margin in accordance with NRC requirements. The bases for this position are described in detail in the testimony.

A. <u>Corrosion and UT Measurements</u>

Corrosion of the sand bed region of Oyster Creek's drywell shell was identified in the late 1980s, but corrective actions taken, including removal of the sand from the sand bed region and application of a multi-layer epoxy coating in 1992, protect the drywell from additional corrosion. Testimony at A5.

The likelihood of a corrosive environment existing during operation of Oyster Creek is very low because the drywell is inerted during operation. *Id.* at A12(a) However, because certain leakages from components inside the drywell can create a corrosive environment during outages, AmerGen committed to monitoring the two trenches for the presence of water until no water is identified for two consecutive outages. *Id.* Implementation of this commitment will ensure that the embedded portion of the drywell shell is not subjected to corrosion. *Id.*

As far as eliminating sources of water, AmerGen has committed to monitor the sand bed region drains quarterly during the operating cycle and take corrective actions if water is found. *Id.* at A12(b). AmerGen has also committed to using a strippable coating during the proposed period of extended operation that has been shown to be effective in mitigating water intrusion into the annular space between the drywell shell and the shield wall. *Id*.

The Staff's position is, contrary to Citizens' assertion (*see* Supplement, July 25, Hauser Memo at 5-6), that corrosion (not visible to an inspector) will not occur in pinholes or holidays in the epoxy coating on the external surface of the drywell. *Id.* at A13. First, AmerGen has applied a multi-layer epoxy coating (i.e. one pre-primer, and two top coats) to the exterior of Oyster Creek's drywell shell in the sand bed region. *Id.* at A14. The use of multiple layers of epoxy coating results in an extremely low probability that pinholes or holidays will line-up in the three-layer coating. *Id.* Second, AmerGen has committed to conducting inspections of the coatings in the sand bed region in accordance with ASME Code Section XI, Subsection IWE (Commitment 27 Items 4 and 21 and Commitment 33). *Id.* at A13.

Corrosion will be visible because when steel corrodes it produces an oxide film which is higher volume and different in color than the original steel. *Id.* at A15. This film will be obvious against the gray color epoxy coating, especially to qualified inspectors performing VT-1 inspections in accordance with AMSE Code Section XI, Subsection IWE. *Id*.

In March 2006, the Staff conducted license renewal inspections at Oyster Creek. *Id.* at A16. The NRC inspectors reviewed AmerGen's drywell aging management program (ASME Section XI, Subsection IWE) and found it consistent with guidance for managing the effects of aging on the drywell. *Id.* The Staff also reviewed AmerGen's Protective Coating Monitoring and Maintenance Program (i.e. the program for monitoring the coating on the exterior of the drywell) and concluded that the program provided adequate guidance to ensure that effects of aging on the drywell shell, including the sand bed regions, will be adequately managed. *Id.*

Reactor Inspector Timothy O'Hara inspected the epoxy coatings in Bays 11 and 13 during the 2006 outage. *Id*. at A20. He noted that the coating in both Bays was grayish-white in color, appeared to be in excellent condition with no visible evidence of cracking, peeling, or blistering, and that there was no visible moisture. *Id.* Mr. O'Hara did not see any sign that corrosion had disturbed the epoxy coating and saw no evidence that corrosion was occurring under the coating. *Id.* Mr. O'Hara also reviewed videos of inspections of all the Bays and saw no evidence of moisture, a corrosive environment, or deterioration of the epoxy coating. *Id.*

On pages 4-59 and 4-60 of the SER, the Staff evaluates the process used by AmerGen related to UT measurements taken after the epoxy coating was applied. *Id.* at A22. During the Regional Aging Management inspection in March 2006, the Staff reviewed the historical evolution of the drywell corrosion issue and inquired about Oyster Creek's past UT data and data collection procedures. *Id.* at A18. The Staff concluded that Oyster Creek has completed a well-documented baseline inspection on the internal and external drywell condition, which will be reinspected, at appropriate intervals based upon recently-measured corrosion rates, to ensure that the drywell wall thicknesses remain adequate. *Id.*

During the 2006 outage, Reactor Inspector O'Hara observed the use of a qualified UT procedure, performed by qualified technicians. *Id.* at A17. AmerGen was able to obtain comparison readings for 106 of 115 points. *Id.* AmerGen employed a UT measurement technique (automatic nullification of the epoxy coating thickness) that eliminates an additional measurement step that was required by previous UT measurement techniques. *Id.* at A19. This new technique provides more consistent and accurate measurements than the technique used prior to 2006. *Id.* at A19.

The results of the 2006 UT measurements do not indicate any significant corrosion that would challenge the integrity of the drywell shell. *Id.* at A21. Corrosion is not occurring at a rate that warrants UT measurement at an interval shorter than in AmerGen's Commitment 27, Item 21 (i.e., every other outage). *Id.* at A11.

AmerGen has committed to performing a full scope inspection of the drywell sand bed region during inspections prior to the period of extended operation and every other outage thereafter. *Id.* at A10. Any anomaly associated with inspections during the 2008 outage will tracked prior to the start of license renewal period. *Id.* The Staff found the frequency of inspections adequate because UT measurements taken during the 2006 outage confirmed that the epoxy coating in the sand bed area has been effective in reducing the potential for corrosion in this area since the changes in thicknesses were so small. *Id.* at A11.

B. Acceptance Criteria

As stated in the SER, the Staff concluded that AmerGen's aging management program is consistent with GALL AMP XI.S1, AMSE Section XI, Subsection IWE such that the effects of aging will be adequately managed for the period of extended operation provided AmerGen effectively implements enhancements to it aging management program. *Id.* at A7.

The current licensing basis for Oyster Creek's drywell shell is based on the General Electric (GE) analyses performed in 1991-1992. *Id*. The objective of the analyses was to provide reasonable assurance that the structural integrity of the as-built shell would be maintained under refueling conditions, by showing that the stresses do not exceed ASME Section III Subsection NE limits. *Id*.

The term "buckling" refers to "linear bifurcation buckling," which is the state where adjacent equilibrium configurations of the shell may exist under the same loading condition. *Id.* at A7. Buckling has been identified as the governing failure mode of the drywell shell in the degraded sand bed region (i.e., the bathtub ring) under refueling load conditions. *Id.* The GE analysis included a buckling analysis of Oyster Creek's drywell shell, considering a uniform reduction in the sand bed region wall thickness due to corrosion to 0.736 inches. *Id.* The GE analysis also included a buckling analysis that modeled locally thinned areas in the sand bed region. *Id.* The assumed wall thicknesses in this analysis were 0.536 inches and 0.636 inches, extending over a square foot area tapering to 0.736 inches over a 9 square foot area. *Id.* GE's analysis showed that the postulated wall thinning did not have a significant effect on the allowable buckling loads. *Id.* Oyster Creek adopted GE's criteria to assess locally thinned areas. *Id.*

Based on information received from the 2006 outage inspection, the Staff concluded that overall changes in the extent of drywell shell corrosion since 1992 are relatively small and are bounded by GE's analyses. *Id*. The Staff found that GE's analyses would remain valid for the extended period of operation. *Id.* Nevertheless, the Staff did not rely solely on the results of the GE analysis. *Id.* at A8. The Staff asked Sandia National Laboratory to perform a confirmatory analysis. *Id.* Sandia performed an analysis of the degraded drywell shell using advanced techniques for modeling and analyzing the complex shell structure to determine the controlling loads. *Id.* Sandia confirmed that Oyster Creek's degraded shell can withstand the postulated load conditions without exceeding ASME Code allowable limits. *Id*. Sandia's analysis provides assurance that Oyster Creek's drywell can fulfill its intended functions. *Id.*

As stated above, Oyster Creek adopted GE's criteria for assessing locally thinned areas. Based upon its review of GPU Nuclear Calculation C-1302-187-5320-024, Rev. 1 (AmerGen Exhibit 17), the Staff concludes that AmerGen has developed three criteria related to acceptance (1) general minimum average required thickness of 0.736 inch, (2) a minimum locally thin thickness of 0.536 inch, in an area of one square foot, with a surrounding one foot transition area to 0.736 inch, and (3) the minimum thickness of 0.49 inch in an isolated area not exceeding an area of a circle having a diameter of two and one-half inches. *Id.* at A.9. AmerGen has elected to use a thickness of .636 inched to characterize the extent of degradation below 0.736 inch. *Id.*

The Staff did not consider Calculation C-1302-187-5320-024, Rev. 2 (March 2007) (AmerGen Exhibit 16) during review of the LRA. *Id.* Although the Staff had not conduct a detailed review of Rev 2, Section 6, it appears that Calculation-24, Rev. 2 criterion related to the locally thinned areas is a more stringent criterion, but is encompassed by the criterion of 0.536 discussed in the SER at 4-55 to 4-61. *Id*.

In sum, contrary to Citizens' assertion, the Staff's position is that the AmerGen Aging Management Program will adequately manage the condition of the drywell shell during the license renewal period. *Id.* at A24. Based on the condition of the Oyster Creek drywell shell in the sand bed region during the 2006 outage, the AmerGen Aging Management Program, as enhanced by commitments to perform UT inspections every other outage (as required by proposed license condition), provides reasonable assurance that drywell shell integrity (and the intended function of the drywell) will be maintained during the period of extended operation. *Id.*

CONCLUSION

For the reasons discussed above, AmerGen's UT monitoring frequency is sufficient to maintain an adequate safety margin in accordance with NRC requirements thus, Citizens' contention lacks merit.

Respectfully submitted,

/RA/

Mitzi A. Young
Counsel for NRC Staff

/RA/

Mary C. Baty
Counsel for NRC Staff

Dated at Rockville, Maryland
this 20th day of July, 2007

July 20, 2007

UNITED STATES OF AMERICA
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NRC STAFF TESTIMONY OF HANSRAJ G. ASHAR,
DR. JAMES A. DAVIS, DR. MARK HARTZMAN AND
TIMOTHY L. O'HARA CONCERNING DRYWELL CONTENTION

Q1. Please state your name, occupation, and by whom you are employed.

A1(a). My name is Hansraj G. Ashar ("Ashar").[1] I am employed as a Senior Structural Engineer in the Division of Engineering, Office of Nuclear Reactor Regulation ("NRR"), U.S. Nuclear Regulatory Commission ("NRC"). A statement of my professional qualifications is attached hereto.

A1(b). My name is Dr. James A. Davis ("Davis"). I am employed by the NRC as a Senior Materials Engineer in the Office of Nuclear Reactor Regulation ("NRR"), Division of License Renewal. A statement of my professional qualifications is attached hereto.

A1(c). My name is Dr. Mark Hartzman ("Hartzman"). I am employed by the NRC as a Senior Mechanical Structural Engineer in the Division of Engineering, Office of Nuclear Reactor Regulation ("NRR"). A statement of my professional qualification is attached hereto.

A1(d). My name is Timothy L. O'Hara ("O'Hara"). I am employed by the NRC as a Reactor Inspector in the Division of Reactor Safety, Region I Office. A statement of my

[1] In this testimony, the sponsors of each numbered response are identified by their last name; no such designation is provided for paragraphs which are sponsored by all witnesses.

professional qualification is attached hereto.

Q2. Please describe your current responsibilities.

A2(a). (Ashar) I am responsible for performing safety reviews of nuclear power plant structures including containment structures and various structural supports for the operating nuclear power issues, license renewal applications, and new reactor design certifications. For the last 33 years, I have reviewed plant license and license renewal applications, and have been involved in nuclear power plant standards development. In license renewal activities, I was the lead technical coordinator for development of Chapter II of Generic Aging Lessons Learned (GALL) related to the positions on PWR and BWR containments. I have reviewed the containment section of license renewal applications for PWR and BWR plants. For the BWR containments, I have principally reviewed drywell shells, tori and connecting vents to ensure the integrity of these pressure retaining structural components during the period of extended operation. As part of my duties, I represent the NRC on committees for a number of organizations that develop standards related to nuclear power plant structures, namely, the American Society of Mechanical Engineers (ASME), American Concrete Institute, and American Institute of Steel Construction.

A2(b). (Davis) Since November 2005, I have served as an audit team leader and as an audit team member for license renewal audits. Prior to joining the Division of License Renewal, I was the lead researcher on steam generator issues in the Materials Engineering Branch of the Office Nuclear of Regulatory Research and a technical reviewer in the Materials and Chemical Engineering Branch of NRR, Division of Engineering, responsible for conducting reviews of coating issues, corrosion of metals, service water issues, threaded fasteners, and license renewal. I have worked on coatings and corrosion control since 1968 and have worked on coating issues in nuclear facilities for the past sixteen years at the NRC. I was the NRC representative to ASTM D-33, "Coatings for Power Generation Facilities." This committee prepared standards for testing and inspection of coatings for nuclear power plants. Prior to joining the NRC, I was a member of the NACE Technical Practices Committee on Pipeline Coatings where we wrote standards for the testing and inspection of pipeline coatings including epoxy coatings. These standards included testing to detect pinholes or holidays. I was also a member of the American Water Works Association Technical Advisory Committee on Coatings for Steel Water Pipe and elected Chairman of this committee in 1989. The work of this committee included writing standards for epoxy coated pipe, including requirements for holiday and pinhole testing.

A2(c). (Hartzman) I am responsible for reviewing safety analyses of ASME Section III Class 1, 2 and 3 and non-ASME piping systems and components submitted by licensees in license amendment requests. The reviews evaluate licensee-submitted structural integrity analyses of piping systems and components under various Service Level operating conditions, and verifying that the stresses meet the ASME Code Section III or other acceptance criteria for strength and fatigue for each operating service level. I assist regional offices with the evaluation of technical issues arising during inspection activities and, as part of reviews of license renewal applications, evaluate time limited aging analyses of ASME Section III metal components. I represent the NRC at ASME Section III Code-writing working groups, such as the WG Vessels and the WG on Methods Development, and I review ASME Section III Code Cases for NRC endorsement.

A2(d). (O’Hara) As a reactor inspector, I inspect licensee implementation of inservice inspection (ISI) programs. I also participate in license renewal aging management program reviews of licensee ISI activities. In addition, I perform component replacement inspections (steam generators, pressurizers and reactor vessel heads) and general engineering inspections contained in the Reactor Oversight Program.

Q3. Please explain your duties in connection with the Staff's review of the License Renewal Application ("LRA") submitted by AmerGen Energy Company, LLC, ("AmerGen" , "Applicant" or "Licensee") for the renewal of the Oyster Creek Facility Operating License No. DPR-16.

A3(a). (Ashar) As part of my official duties, I was responsible for the review of the following sections of the LRA: 1) Section 2.4, "Scoping and Screening Results – Structures;" 2) portions of Section 3.5, "Aging Management of Containment, Structures, Component Supports, and Piping and Component Insulation;" 3) Section 4.7.2, "Time Limited Aging Analysis [TLAA] of Drywell Corrosion;" and 4) Section 4.7.3, "TLAA, Equipment Pool and Reactor Cavity Walls Rebar Corrosion." I prepared Section 4.7.2 of NUREG-1875, "Safety Evaluation Report Related to the License Renewal of Oyster Creek Nuclear Generating Station" (March 30, 2007 (published April 2007) ("SER") (ML070890637). Excerpts from the SER are attached hereto as Staff Exhibit 1. The primary objective of my review is to ensure that there is reasonable assurance that the structural integrity and the safety functions of power plant structures, including a containment structure such as the drywell shell, are maintained when subjected to various combinations of the postulated loads including design basis earthquake and accident loads.

A3(b). (Davis) As part of my official duties, I was an audit team member for the license renewal safety audit at Oyster Creek. I reviewed the Oyster Creek LRA, including the following aging management programs: B.1.11, "Flow Accelerated Corrosion;" B.1.12, "Bolting Integrity;" B.1.15, "Boraflex Monitoring;" B.1.21, "Above Ground Tanks;" B.1.21A, "Above Ground Tanks-Forked River Construction Tower;" B.1.25, "Selective Leaching;" B.1.26, "Buried Pipe Inspection;" B.1.26B, "Met. Tower Repeater Engine Fuel Supply – Buried Pipe Inspection;"

B.2.02, “Lube Oil Monitoring Activities;” and B.2.52, “Periodic Inspection,” including preparation of Section 3.0.3 of the SER. I also reviewed aging management reviews not consistent with GALL and prepared Sections 3.1.2.3, 3.2.2.3, 3.3.2.3, 3.4.2.3, 3.5.2.3, and 3.6.2.3 of the SER.

A3(c). (Hartzman) As part of my official responsibilities, I reviewed the applicability of ASME Section III, Division 1 Code Case N-284-1, “Metal Containment Shell Buckling Design Methods, Class MC,” (Code Case N-284-1) to the buckling analyses of the Oyster Creek drywell shell performed by General Electric (GE) and the Sandia National Laboratory (SNL). My expertise is based on my (1) education and experience in the field of Engineering Mechanics, which includes the subject of structural stability theory, (2) experience in reviews of structural and mechanical safety evaluation reports, (3) review of the Code Case for NRC endorsement acceptability, and (4) participation, as the NRC representative, in the ASME Section III Working Group on Vessels, which is responsible for maintaining and updating Code Case N-284-1.

A3(d). (O’Hara) As part of my reactor inspector duties, I participated in the License Renewal Aging Management Inspection conducted in March 2006 at the Oyster Creek Nuclear Generating Station. During this inspection, I reviewed the following Aging Management Programs: B.1.27, ASME, Section XI, Subsection IWE Program; and B.1.33, Protective Coating Monitoring and Maintenance Program. I also participated in the NRC inspection of Amergen’s implementation of some license renewal commitments regarding the drywell shell and torus during the Fall 2006 outage at Oyster Creek, and provided information about my inspection activities at Oyster Creek as part of the Staff’s presentation at the January 2007 meeting of the Advisory Committee on Reactor Safety (“ACRS”).

Q4. What is the purpose of your testimony?

A4. The purpose of this testimony is to present the Staff’s position regarding Citizen’s contention. As admitted by the Board, LBP-06-22, 64 NRC at 255-56, alleges that:

> [I]n light of the uncertain corrosive environment and the correlative uncertain corrosion rate in the sand bed region of the drywell shell, AmerGen's proposed plan to perform UT tests prior to the period of extended operations, two refueling outages later, and thereafter at an appropriate frequency not to exceed 10-year intervals is insufficient to maintain an adequate safety margin.

We have read relevant portions of: the SER; LBP-06-22, 64 NRC 229 (2006); Citizens' "Petition to Add a New Contention" (June 23, 2006) ("June 23 Petition"); Citizens' "Supplement to Petition to Add a New Contention" (July 25, 2006) ("Supplement") and the attached Memorandum from Dr. Rudolf H. Hausler to Richard Webster (July 25, 2006) ("July 25 Hausler Memo"); "AmerGen's Motion for Summary Disposition of Citizens' Drywell Contention" (Mar. 30, 2007); "Citizens' Answer Opposing AmerGen's Motion for Summary Disposition" (Apr. 26, 2007); "Citizens' Response to NRC" (May 7, 2007); the "Memorandum and Order (Denying AmerGen's Motion for Summary Disposition)" (June 19, 2007) (unpublished); and the "Memorandum and Order (Clarifying Memorandum and Order Denying AmerGen's Motion for Summary Disposition)" (July 11, 2007).

A4(a). (Ashar) My testimony will address the Staff's review of AmerGen's aging management program for the aging effect of corrosion on the drywell shell with respect to the Staff's conclusion that there is reasonable assurance that AmerGen's drywell monitoring plan is sufficient to ensure that the drywell can perform its intended function during the proposed license renewal period.

A4(b). (Davis) My testimony will address Citizens' claim that visual inspections of epoxy coating do not reveal that the coating has deteriorated because corrosion may occur under the epoxy coating in the absence of visible deterioration due to nonvisible holidays, or pinholes.

A4(c). (Hartzman) My testimony will address, in the context of license renewal, the Staff's review and evaluation of ASME Code Case N-284 as applied to the stability analysis of the drywell shell.

A4(d). (O'Hara) My testimony will provide my observations of the condition of the sand bed region of the drywell shell and the Staff's inspection findings concerning AmerGen's commitments related to license renewal and the drywell.

Q5. Describe the corrosion in the sand bed region of the drywell shell at Oyster Creek.

A5. Corrosion of the sand bed region of the Oyster Creek drywell shell was identified in the late 1980s. SER at 4-42. The accumulation of water from leaks from the reactor cavity into the gap between the drywell shell and the shield concrete during refueling outages caused corrosion of the exterior of the drywell shell in the sand bed region. Significantly corroded areas in the sand bed region are referred to as the "bathtub" ring of corrosion. Because the high corrosion rate in the sand bed region was attributed to galvanic corrosion of the drywell shell caused by water retained in the sand due to a lack of proper drainage, corrective actions taken included removal of the sand in 1992 and the application of a protective coating to protect the drywell shell from additional corrosion. *See* SER at 4-42 to 4-43 (citing AmerGen RAI Response, dated April 7, 2006).

Prior to coating the shell, thickness measurements were taken in each of the 10 bays, from outside the drywell, to establish the minimum general and local thickness of the thinned shell. *Id. at* 4-43. Measurements from outside the drywell showed a minimum average thickness generally greater than .800 inches (some local areas were less than .800 inches), but the minimum average thickness in these areas was greater than the .736 inches required to satisfy ASME Section III Code requirements for structural integrity of the drywell. *Id.* at 4-43.

Q6. How was the corrosion of the drywell shell considered in the Staff's review of the Oyster Creek LRA?

A6. (Ashar) The Staff reviewed LRA Section 3.5, which contains AmerGen's aging management review results for the drywell, and Section 4.7.2, the TLAA analysis, to determine whether the degraded condition of the drywell shell could withstand the postulated loadings stipulated in the plant's Final Safety Analysis Report (FSAR) without exceeding acceptance criteria. In the description of TLAA 4.7.2, the Applicant states that its ASME Section XI, Subsection IWE aging management program (B.1.27) ensures that drywell shell thickness will not be reduced to less than the minimum required value in any future operation. LRA at 4-55. The Applicant further states that the effects of loss of material on the intended function of the drywell will be adequately managed in accordance with 10 CFR 54.21(c)(1)(iii) for the period of extended operation. *Id.*

Due to the extent of reported drywell shell degradation in the sand bed area, the Staff sent requests for additional information (RAIs) about differences in 1994 and 1996 UT results, comparison of such results to UT results in 1992, measurement errors, statistical approach in interpreting the UT results, corrosion rates in the upper spherical and cylindrical areas, and the ability to replicate the locations of UT measurements. In March and April 2006, the Staff was at Oyster Creek, discussed some of these RAIs, and discussed earlier Oyster Creek efforts to mitigate future corrosion. The Staff discussed RAIs during a public meeting at NRC Headquarters on June 1, 2006. NRC inspectors observed UT measurements taken during the 2006 outage and provided updates about AmerGen's drywell activities. The Staff also reviewed AmerGen's statistical analysis of previous measurements in Calculation C-1302-187-5300-11, "Statistical Analysis of Drywell Shell Thickness Data Thru 4-24-90" (6/13/90) (see ML06490205) (AmerGen Exhibit 23) and the analysis in Calculation C-1302-187-5320-24, Rev. 0, "OC Drywell Ext. UT Evaluation in Sandbed" (4/16/93) ("Calculation-24") (AmerGen Exhibit 18), and Calculation-24, Rev. 1 (9/21/06) (AmerGen Exhibit 17). *See* SER at 59-60.

Q7. What did the Staff conclude about whether the degraded drywell shell can fulfill its intended function during the period of extended operation?

A7. (Ashar, Hartzman) As stated in SER, the Staff concluded that AmerGen's aging management program is consistent with GALL AMP XI.S1, ASME Section XI, Subsection IWE such that the effects of aging will be adequately managed for the period of extended operation provided AmerGen effectively implements enhancements to its aging management program. *See* SER at 3-143, 4-75. As part of the containment, the drywell shell is required to provide a pressure retaining function under all the postulated loadings. *See* OCNGS FSAR at 3.8-10 to 3.8-19. The current licensing basis for the Oyster Creek is based on analyses performed by General Electric (GE) 1991-92 in GE Reports 9-3, 9-4, "ASME Section VIII Evaluations of the Oyster Creek Drywell for Without Sand Case [Stress and Stability Analyses] – February 1991" (ML0610206140), which are discussed, for example, in the SER at 4-55 to 4-58. The objective of the GE structural analysis of the drywell shell was to provide reasonable assurance that the structural integrity of the as-built shell (i.e., with the degraded wall thickness in the sand bed region) will be maintained under this loading condition, by showing that the stresses do not exceed the ASME Section III Subsection NE stress limits, and that the compressive stress (buckling) requirements of ASME Section III, Code Case N-284 are satisfied.

The term "buckling" refers to "linear bifurcation buckling," the state where adjacent equilibrium configurations of the shell may exist under the same loading. This loading is called the "theoretical buckling load," and is determined from a type of structural analysis called "bifurcation buckling" analysis. Local imperfections in thin-walled shells, resulting from the fabrication processes, significantly affect the buckling of fabricated thin-walled shells. Thus, actual buckling of such a shell may occur at a load considerably lower than the theoretical buckling load. Buckling has been identified as the governing failure mode of the drywell shell in the degraded sand bed region under the refueling loading condition. In the refueling condition, the drywell shell is loaded in the vertical direction by gravity and inertia type loads. The minimum uniform degraded sand bed wall thickness necessary to prevent buckling under this loading condition is determined from a buckling analysis of the sand bed region. The criteria in ASME Section III Code Case N-284 are appropriate for determining the stability of the degraded drywell shell.

The GE analysis included a bifurcation buckling analysis of the Oyster Creek drywell shell, considering the uniform reduction in the sand bed region wall thickness due to corrosion to 0.736 inches. The analysis, based on the finite element method, determined that, in this portion of the drywell spherical shell, the axial (meridional) stresses were compressive and the hoop (circumferential) stresses were tensile. This analysis provided the theoretical and allowable buckling stresses for the sand region.

In 1992, the Staff's review of that analysis concluded that the Oyster Creek drywell shell analysis was performed in accordance with ASME Code Case N-284 and showed that (1) the load combinations critical to buckling were those involving refueling and post-accident conditions, and (2) application of a factor of safety of 2 and 1.67 for load combinations involving refueling and post-accident conditions, respectively, showed the drywell had adequate margin against buckling with no sand support for an assumed average sand bed region thickness of 0.736 inches. *See* Letter from Alexander Dromerick, NRC, to John Barton, GPU Nuclear Corporation, dated April 24, 1992 (enclosing Evaluation Report on Structural Integrity of the Oyster Creek Drywell) (ML070290668) ("1992 SE"), at 4. The Staff found that the procedure used to calculate buckling requirements consistent with ASME Code Case N-284. *See* SER at 4-61 to 4-63.

GE also performed additional buckling analyses where locally thinned areas in the sand bed region were modeled. *See* SER at 3-128. The assumed wall thicknesses in these analyses were 0.536 inches and 0.636 inches, extending over a square foot area and transitioning to a thickness of 0.736 inches over a 9 square foot area. GE used a refined finite element model which took advantage of the symmetry of the modeled degraded area. The analysis showed that the postulated wall thinning did not have a significant effect on the allowable buckling loads. Oyster Creek adopted these results as criteria for assessing local wall thinning in the sand bed region. *See*, *e.g*. Calculation-24, Rev.1 (AmerGen Exhibit 17) at 10 of 117. *See also* SER at 4-56 to 4-58.

Based on information received from the 2006 outage inspection, the Staff concluded that overall changes in the extent of drywell shell corrosion since 1992 were relatively small and were bounded by the analysis and calculations done by GE. *See* SER at 3-137 to 3-143, 4-72 to 4-73. Therefore, the Staff concluded that the degraded drywell will be able to perform its intended function and the effects of aging will be adequately managed during the extended period of operation, provided AmerGen implements commitments to its aging management program. *See, id* at 3-422 to 3-424, 4-73 to 4-75.

Q8. Did the Staff rely solely on the results of the 1992 GE analysis?

A8. (Ashar, Hartzman) No. In order to provide additional assurance that the aging management program would ensure that the drywell shell could perform during the renewal period, the Staff asked Sandia National Laboratories (Sandia) to perform an analysis of the degraded drywell shell based on advanced techniques for modeling and analyzing the complex shell structure and to determine controlling postulated load conditions. *See* SER at 4-71. Sandia developed a full (360 º) three dimensional (3D) finite element model of the Oyster Creek drywell shell that permitted a more sophisticated analysis of structural details that accounted for asymmetries of drywell shell. Sandia used the degraded shell thicknesses in the Applicant's

Calculation-24, Rev. 0 (AmerGen Exhibit 18) and performed analyses for both the undegraded and degraded shell. For the degraded shell, the load condition with a minimum margin against the ASME allowable limits was found to be the refueling condition. For this loading condition, the safety factor against buckling was found to be 3.85 for the undegraded shell and 2.15 for the degraded shell. For the operational load condition, such as the refueling condition, the ASME Code requires a minimum safety factor of 2.00. Thus, the Sandia analysis confirmed that the Oyster Creek degraded drywell shell could withstand the postulated load conditions without exceeding the ASME Code, Section III, Subsection NE. *See* SER at 4-72. This confirmation provides assurance that the Oyster Creek drywell shell can fulfill its intended function of providing the pressure retaining barrier against uncontrolled release of radioactivity under all postulated load conditions, provided the drywell shell does not experience significant additional degradation.

Q9. You testified that the Sandia analysis used information from the 1993 version of Calculation-24. Did the Staff consider information in later versions of that calculation during its review of AmerGen's LRA?

A9. (Ashar) Yes. The Staff was aware of Calculation-24, Revision 1 (AmerGen Exhibit 17), which had used the same 1992 bathtub area measurements that are in Rev.0. In Calculation-024, Rev. 0 (AmerGen Exhibit 18), there are eight raw 1992 UT data points in Bay 1, that are between 0.636 inch and 0.736 inch, and no UT data point is less than 0.636 inches. In Bay #13, there are nine raw data points between the thickness of 0.636 inch and 0.736 inch, and one data point (i.e., 0.618 inch) below 0.636 inch, but above 0.536 inch. AmerGen has adjusted the raw data points less than 0.736 inch to account for surface roughness for their use in its structural evaluation. *Id.* at 67-87 of 117.

Based on a review of the Calculation-24, Revs. 0 and 1 (AmerGen Exhibits 18 and 17) analysis of degraded areas, and AmerGen responses to Staff RAIs (*see* SER section 4.7.2), AmerGen has three criteria related to acceptance of the shell thicknesses: 1) a general minimum average required thickness of 0.736 inch; (2) a minimum locally thin thickness of 0.536 inch, in an area of one square foot, with a surrounding one foot transition area to 0.736 inch; and (3) the minimum thickness of 0.49 inch in an isolated area not exceeding an area of a circle having a diameter of two and one-half inches. *E.g.*, Calculation-24, Rev. 1 (AmerGen Exhibit 17) at 10-11 of 117. In addition, AmerGen has elected to use a thickness of 0.636 inch to characterize the extent of degradation below 0.736 inch. *See id.*

The Staff did not consider Calculation C-1302-187-5320-024, Rev 2 (Mar. 2007) (AmerGen Exhibit 16) during the review of the LRA because that document was not submitted to the NRC for review in connection with the LRA (or available before issuance of the SER). Although the Staff has not conducted a detailed technical review of Calculation-24, Rev. 2, Section 6.0 (at 10-15 of 183) of the calculation indicates that AmerGen analyzed 2006 UT results from the drywell exterior using a local acceptance criterion different from a previous version of the calculation. Section 6.1 of Calculation-24, Rev. 2, indicates a general uniform wall thickness criterion of 0.736 inch and methods for implementing the criterion under various UT measurements, but a local wall thickness criterion for buckling as an average of 0.636 inch in an area no larger than 12 inches by 12 inches square. *See* AmerGen Exhibit 16 at 10-15 of 183**.** The criterion allows the transition (from 0.636 inch to 0.736 inch) thickness in the area no larger than 36 inches by 36 inches square. *Id.* However, Revision 2 refers to the same analysis that was used in Calculation-24**,** Revisions 0 and 1. The very local wall thickness criterion of 0.49 in an area not exceeding a 2½ inch diameter circle has not changed. Thus, it appears that the Calculation -24, Revision 2 criterion for locally thin areas (i.e., 0.636 inch) is a more stringent criterion, and is encompassed by the Staff's review based on a very local criterion of 0.536 inch discussed at SER pages 4-55 to 4-60.

Q10. How often will UT measurements of the sand bed region of the drywell be taken under AmerGen's aging management program?

A10. (Ashar) In LRA, section B.1.27, "ASME Section XI, Subsection IWE," AmerGen indicates that inspection of the drywell shell and other primary containment components is in accordance with this aging management program. LRA at B-75**.** Commitment 27, Item 21, indicates that, during the period of extended operation AmerGen will perform the full scope of drywell sand bed region inspections prior to the period of extended operation and then every other refueling outage thereafter. The full scope inspection is defined as:

- UT measurements from inside the drywell
- Visual inspections of the drywell external shell epoxy coating in all ten bays
- Inspection of the seal at the junction between the sand bed region concrete and the embedded drywell shell
- UT measurements at the external areas inspected in 2006.

The Staff found AmerGen's Commitment 27 items acceptable. *See* SER at 4-75. As noted in the SER (at 1-18), the Staff plans to include a license condition that requires the applicant to perform full scope inspections of the drywell sand bed region every other refueling outage during the proposed renewal period.

Q11. Why did the Staff find the monitoring frequency adequate?

A11. (Ashar, Davis) UT measurements taken during the October 2006 outage confirmed that the epoxy coating in the sand bed area has been effective in reducing the potential for corrosion in this area since the change in thicknesses were small. In its letter of December 3, 2006 (ML063390664) (AmerGen Exhibit 12), AmerGen indicated that wall thinning of 0.038 inch had taken place in trenches 5 and 17, since 1986, when the trenches were constructed. *See* SER at 3-423 to 4-424. These trenches are in the inside of the drywell and do not have an epoxy coating to prevent corrosion. This corrosion identified in the trenches is equivalent to about 2 mils per year of corrosion in the specific areas of the trenches.

The Staff reasoned that, if this corrosion rate is applied to the lowest average thickness of 0.8 inch for four years, the average thickness would be reduced to 0.792 inch, and hence, higher than the average minimum required thickness of 0.736 inch. This approach is conservative because it involves the application of a very local thickness reduction to the entire sand bed region and, because the rate of future corrosion normally decreases over time due to the formation of corrosion products. In addition, AmerGen has committed (Commitment 27, Items 16, 20 and 21) to perform inspections during the 2008 outage, which will include UT examinations in the trench areas, as well as in the rest of the sand bed area. *See* SER at 4-74 to 4-75. Any anomaly associated with these measurements will be tracked prior to the start of the extended period of operation. In summary, the Staff's view is that no significant corrosion is occurring in the sand bed area at a rate that would warrant the UT measurement at an interval shorter than in Commitment 27, Item 21 (*i.e.*, every other outage).

Q12. Can a corrosive environment exist in the sand bed region after removal of the sand and application of the epoxy coating?

A12(a). (Ashar) Because the drywell is inerted during operation, the likelihood of corrosive environment existing inside the drywell during operation of the plant is very low. However, certain leakages from components inside the drywell can create a corrosive environment during outages, as found in the trenches during the October 2006 inspections. In Commitment 27, Item 20 (*see* SER at A-31 to A-32), AmerGen committed to monitor the two trenches for the presence of water.

> Visual and UT inspections of the shell within the trenches will continue to be performed until no water is identified in the trenches for two consecutive refueling

> outages, at which time the trenches will be restored to their original design (e.g., refilled with concrete) to minimize the risk of future corrosion.

Proper implementation of this commitment will ensure that the embedded portion of the inside of the drywell shell will not be subjected to corrosion. Routine implementation of IWE program (LRA AMP B.1.27) will ensure that the junction between the bottom concrete floor and the drywell shell is monitored during each inspection period.

A12(b). (Davis) As far as eliminating sources of water, Oyster Creek has committed (Commitment 27, Item 3) to monitor the sand bed region drains quarterly during the operating cycle. If water is detected, the following actions will be taken: 1) The leakage rate will be quantified for flow rate and trended; 2) The source of water will be investigated and diverted, if possible, from entering the sand bed region; 3) The water will be analyzed to determine the source of leakage; 4) If a leak is detected, the coating and moisture barrier will be inspected in any bays affected by the leakage during the next refueling outage or outage of opportunity; 5) If the coating is degraded, and visual inspection indicates corrosion has taken place, then UT measurements will be taken in the affected areas of the sand bed region from either the inside or outside of the drywell to ensure that the shell thickness in areas affected by water leakage is measured; 6) UT measurements will be taken in the upper region of the drywell consistent with the existing program; and 7) Any degraded coating or seal will be repaired in accordance with station procedures. *See* SER at 1-17.

Oyster Creek has also committed (Commitment 27, Item 2) to use a strippable coating during the period of extended operation that has been shown to be effective in mitigating water intrusion into the annular space between drywell shell and shield wall. This has been applied to the refueling cavity liner during periods when the refueling cavity is flooded. This commitment applies to refueling outages prior to and during the period of extended operation. *See* SER at 3-115.

Q13. Citizens contend that corrosion (not visible to an inspector) can occur in pinholes or holidays in the epoxy coating on the external surface of the drywell. Do you agree?

A13. (Davis) In my opinion, Citizens' contention lacks technical merit because AmerGen has committed to conduct inspections of the coatings in the sand bed region in accordance with the ASME Code Section XI, Subsection IWE. *See* Commitment 27, Items 4 and 21 and Commitment 33 in SER, Appendix A. During the audit at Oyster Creek, the Applicant stated that visual inspection of the containment drywell shell, conducted in accordance with ASME Section XI, Subsection IWE, is credited for aging management of accessible areas of the containment drywell shell. Typically this inspection is for internal surfaces of the drywell. The exterior surfaces of the drywell shell in the sand bed region for Mark I containment are considered inaccessible by ASME Code Section XI, Subsection IWE; thus, visual inspection was not possible for a typical Mark I containment before the sand was removed from the sand bed region in 1992. After removal of the sand, an epoxy coating was applied to the exterior wall in the sand bed region. *See* SER at 3-118 to -119. Excerpts from Subsection IWE are attached as Staff Exhibit 2.

Q14. What is the potential for corrosion under epoxy coating due to defects in and deterioration of the coating?

A14. (Davis) There is a multi-layer epoxy coating on the exterior of the Oyster Creek drywell shell in the sand bed region to prevent corrosion in that region. This coating was discussed in detail under SER Open Item 4.7.2-3, which has been closed. This coating was applied as part of corrective actions taken in the late 1980s and early 1990s to prevent additional corrosion of the drywell shell in the sand bed region. This coating was discussed in detail under Open Item 4.7.2-3 in the SER. In addition to removing the sand from the sand bed region, a coating was applied to the exterior of the drywell shell in the sand bed region with a multi-layered epoxy system (i.e., one pre-primer coat, and two top coats) to prevent any water or moisture that might reach the sand bed region from contacting the exterior shell. *See* SER at 1-15 to 1-18, 3-163 to 3-167, 4-67 to 4-70.

Thus, the use of multiple layers of epoxy coatings at Oyster Creek results in an extremely low probability that pinholes and holidays will line up in the three layer coating system. In addition, pinholes usually develop during the initial cure of the coating and new pinholes would not likely develop over time in the absence of conditions such as mechanical impacts or exposure to ultraviolet light.

Q15. What is the basis for your conclusion that corrosion would be visible?

A15. (Davis) When a steel surface corrodes, the oxide film that is generated has a higher volume than the original volume of the steel because iron in the steel is converted to iron oxide that is then hydrated, which leads to blistering and other observable anomalies in the coating. The film will be rust colored and will be obvious against the gray colored epoxy coating.

AmerGen's protective coating monitoring and maintenance program specifies VT-1 visual inspections of epoxy coating using qualified inspectors. The rust colored corrosion product will be easily detected during VT-1 inspections of the coating on the external surface of the drywell shell in accordance with the ASME Code, Section XI, Subsection IWE. Additional guidance for inspection of the epoxy coatings on the drywell shell are in GALL section XI.S1, "ASME Section XI, Subsection IWE," and XI.S8, "Protective Coating Monitoring and Maintenance Program." These sections indicate that inspectors are to be trained to inspect the surfaces within the scope of IWE for evidence of flaking, blistering, peeling, discoloration, and other signs of degradation. AmerGen has committed to follow this guidance (Commitment 27, Items 4 and 21 and Commitment 33 in the SER Appendix A).

The Applicant further stated that the existing Protective Coating Monitoring and Maintenance Program does not invoke all of the requirements of ASME Code Section XI, Subsection IWE. AmerGen has committed (Commitment 27, Item 4) to enhance the program to incorporate coated surfaces inspection requirements specified in ASME Code Section XI, Subsection IWE and has provided specific enhancements that will be made to the program as follows:

> Sand bed region external coating inspections will be per Examination Category E-C (augmented examination) and will require VT-1 visual examinations per IWE-3412.1.
>
> a. The inspected area shall be examined (as a minimum) for evidence of flaking, blistering, peeling, discoloration, and other signs of distress.
>
> b. Areas that are suspect shall be dispositioned by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.
>
> c. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of engineering evaluation.

SER at 3-120. If the coating is damaged and corrosion is observed, AmerGen will conduct UT measurements of that area and will evaluate the results following the existing program. SER at A-18 to A-20 (Commitment 27, Item 1). The Applicant committed to conduct additional visual inspections of the epoxy coatings applied to the external surface of the drywell shell in the sand bed region prior to entering the period of extended operation. SER at A-22 to A-23 (Commitment 27, Item 4). AmerGen has committed (Commitment 27, Items 4 and 21, and Commitment 33) to enhance the Inservice Inspection Program to require 100% inspection of the epoxy coatings every other refueling outage during the period of extended operation.

The Staff, as noted in SER Sections 3.0.3.2.23 and 3.0.3.2.27, concluded that the performance of ASME Section XI, Subsection IWE, visual inspections of the drywell in all ten bays of the sand bed region every other refuelling outage, and AmerGen taking appropriate actions when significant corrosion is detected, provides assurance that effects of aging will be adequately managed so that intended functions will be maintained throughout the renewal period.

It should also be noted that, Regulatory Guide 1.54, Rev. 1, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," which refers to ASTM D 5163, "Standard Guide for Establishing Procedures to Monitor the Performance of Safety Related Coatings in an Operating Nuclear Power Plant," and ASME Code Section XI, Subsection IWE, "Requirements for Class MC and Metallic Liners of Class CC Components of Light Water Cooled Plants," recommend visual inspection of coatings for evidence of degradation before conducting additional tests.

Q16. What did the NRC learn during license renewal inspections at Oyster Creek?

A16. (O' Hara) As an inspector, I reviewed the implementation of AmerGen's B.1.27, ASME Section XI, Subsection IWE Program, during the March 2006 inspection and found that AmerGen's program was consistent with guidance for managing aging effects of the drywell. This decision was reached after interviews with cognizant engineering and management personnel from AmerGen, review of historical data on the drywell corrosion issue, review of the licensee's evaluation and analysis of the historical drywell testing data, and the licensee's commitment to significantly improve the rigor with which they had been addressing the condition of the drywell and their program to monitor the aging effects of the drywell. See NRC Inspection Report 05000219/2006007 (9/21/06) (ML062650059), at 16. The Staff also concluded, regarding B.1.33, Protective Coating Monitoring and Maintenance Program, that the licensee's program provided adequate guidance to ensure that aging effects of the drywell shell will be adequately managed. *Id.* at 16-17. This program is used to monitor the coating on the exterior of the drywell.

Q17. Did NRC inspectors observe UT measurements of the drywell shell during the Fall 2006 outage?

A17. (O'Hara) Yes. During the fall 2006 inspection, I observed the use of a qualified UT procedure, performed by qualified technicians. Exelon Procedure TQ-AA-122, Revision 3; "Qualification and Certification of Nondestructive (NDE) Personnel" provides the standard used by AmerGen to qualify and certify NDE technicians. In general, UT personnel are qualified in accordance with ASNT SNT-TC-1A, through 1984 edition; ANSI/ASNT CP-189, 1991 and 1995 editions; and ASME Section XI, 1986 Edition through 2001 Edition, 2003 Addenda, as applicable. For UT, personnel certification Attachment 5 of TQ-AA-122 provides the detailed qualification which must be demonstrated to perform examinations for the requirements of ASME Section XI. All the aforementioned standards have been previously reviewed and accepted by the NRC for the specified qualification processes. The calibrations and data collection activities were performed per the procedure, recorded on appropriate data sheets, and the results were reviewed and approved by a qualified, Level III Nondestructive Evaluation Examiner. Then all data was evaluated and analyzed by qualified, experienced engineers to determine whether acceptance criteria were met. Upon confirming that all recorded data met the wall thickness criteria, the Licensee determined that the GE Analysis report of record was validated for the wall thickness data recorded. Based upon the calculated corrosion rate (2006) and the remaining wall thickness, the Licensee demonstrated that the drywell wall thickness will be maintained above minimum requirements until the next refueling outage in 2008.

The UT and visual (VT) records from this inspection in the fall of 2006, were well documented, the data was correctly collected, personnel were knowledgeable and qualified to perform the required inspections. The NDE level III supervising the data collection was knowledgeable and provided accurate direction to the data collection personnel. All data collected was reviewed for acceptability before it was given to engineering. Upon receiving the validated data, engineering personnel conducted appropriate and accurate analyses and evaluations based upon written procedures and criteria. Upon completion of the evaluations, appropriate engineering and station management reviews were conducted.

The external UT wall thickness measurements taken during 2006 showed no significant corrosion compared to1992 measurements. It should be noted that the Licensee had intended to re-measure approximately 115 external points which had been prepared and measured in 1992, prior to application of the epoxy coating. Due to the difficulty in finding and matching up all of these points, the licensee was able to obtain 2006 comparison readings for approximately 106 points of the planned 115. For the external points measurements I observed during the inspection, AmerGen found it difficult to locate and identify some of the points. For example, some measurements had not been ground as deeply as others and some had not been referenced correctly. This indicates that it may not always be appropriate to compare 2006 point readings with external readings from previous years.

During my observations of the internal drywell UT measurements, there was a very light surface coating of oxidation present on small uncoated portions of the drywell shell in the trenches in Bay 5 and 17, however, no wall thickness loss (i.e., flaking) was apparent. The licensee had coated the internal drywell test locations with grease after prior UT measurements in 1994 to prevent this oxidation, but had apparently not coated these areas or the grease was disturbed during preparation for the 2006 inspection. The presence of the water in the trenches in Bay 5 and Bay 17 was the only evidence of a corrosive environment inside the drywell. The Licensee monitors the inside of the drywell under their ASME Section XI, Subsection IWE program, and I verified that the interior of the drywell is inspected and actions taken when coating deterioration is detected. And, in addition, the internal sections of the drywell are measured with UT for wall thickness in the area of the sand bed. The water in the trenches was determined to not be a corrosive environment because the water had reacted with the concrete and had become a non-corrosive (i.e., basic) environment.

Q18. How were the UT measurements taken during the 2006 outage?

A18. (O'Hara) During the 2006 outage measurements, the licensee employed a UT measurement technique (automatic nullification of the epoxy coating thickness) that eliminated an additional measurement step which had been used in previous measurements prior to 2006. Prior to 2006 the licensee had measured the epoxy coating thickness and then manually subtracted the thickness from the recorded thickness of the coating and shell measured together. The new technique, known as wave skip or half-wave technique, involved calibration of the UT instrument to record the first signal reflection of the coating-to-metal interface and deduction of that distance from the overall coating and metal thickness measurement, thus effectively cancelling out the coating thickness and reporting only the remaining metal thickness. This technique had not been used during previous inspections of the drywell thickness after the epoxy coating had been applied in 1992. In my opinion, this technique provided more consistent and accurate measurements than pre-2006 measurements.

During the Regional Aging Management inspection, in March 2006, I was assigned to review the ASME, Section XI, Subsection IWE Program and the Protective Coating Monitoring and Maintenance Program. In reviewing the historical evolution of the drywell corrosion issue, I inquired about the licensee's past data and data collection procedures. Discussions with AmerGen regarding how past data could be directly compared to the 2006 data, in part, led to AmerGen commitments that were verified and results reported in NRC Inspection Report

05000219/2006013 (1/17/07) (ML070170396). Basically, the Licensee has completed a well-documented baseline inspection on the internal and external drywell condition which will be reinspected, at appropriate intervals based upon recently-measured corrosion rates, to ensure that the drywell wall thickness remains adequate to perform its safety function.

Q19. What is your opinion regarding AmerGen's UT measurement uncertainties during the 2006 outage?

A19. (O'Hara) From my observation of the UT equipment calibration, observation of the data collection and the Level III review of the reported data, the measurement uncertainty on these measurements was very low. The use of UT technology as a thickness gauging tool is a very elementary application of the technology and has been shown to be very accurate in many industrial applications. In addition, it is my opinion that the elimination of an additional measurement step to account for the epoxy coating thickness simplified the measurement of the actual remaining metal thickness and enabled measurement with greater accuracy. Also, my experience has been that there would be significant variability in thickness for a manually applied coating applied in the confined space of the external drywell bays. The licensee's use of a technique that accounts for the thickness of the epoxy at each reading location removed a significant potential measurement error. Thus, in my opinion, the 2006 data should be considered to be more accurate than the licensee's previous UT metal thickness measurements.

It is also my opinion, based upon discussions with several licensee personnel about the methods used to remove the sand and scale from the exterior of the drywell and the methods used to prepare the metal surface prior to applying the epoxy coating in 1992, that the licensee has included some additional conservatism in the external UT thickness measurements by not taking credit for metal that was intentionally removed in 1992 prior to applying the epoxy coating. In order to provide a smooth surface for UT readings in 1992, the licensee prepared the dimpled surface of the external locations to be measured by grinding smooth, flat surfaces on the outside of the drywell. During this preparation process, the licensee did not control the amount of material removed. Thus, readings taken since the application of the epoxy coating can be expected to be thinner than the original, 1992 actual thickness by some amount not attributable to corrosion, but attributable to the surface prep process. This added conservatism would affect measurements taken since the application of the epoxy coating, however, because the licensee cannot quantify the amount of this conservatism, no credit has been taken by the licensee in its analysis of the drywell condition. The licensee also has some limited video and pictorial records on the processes followed during the 1992 effort to remove the sand and to clean the drywell and apply the epoxy coating, which I viewed.

Q20. What did you observe regarding the condition of the epoxy coating on the exterior of the drywell shell in the sand bed region?

A20. (O'Hara). During the fall 2006 outage, I inspected (by physically entering the Bays 11 and 13) the external epoxy coating on the outside of the drywell. The coating in both bays was grayish-white in color and appeared to be in excellent condition with no visible evidence of cracking, peeling or blistering. The general condition of each bay was good with no moisture visible. I could not see any sign that corrosion had disturbed the epoxy coating and saw no evidence that corrosion was occurring under the epoxy coating.

In addition to entering Bays 11 and 13, I also viewed video tapes of all Bays and reviewed the VT data sheets from all Bays. The video tapes showed the same general condition in all bays and showed that the epoxy coating had not been visibly disturbed since the original application. The epoxy coating, in all Bays, appeared to be in good condition and undisturbed since the application of the epoxy in 1992.

Regarding the potential for a corrosive environment to exist on the outside of the drywell, my visual observations of (and a review of records concerning) the exterior of the drywell and the epoxy coating condition did not reveal any evidence of moisture on the drywell exterior or the coating in the sand bed region. Additionally, my reviews did not identify any evidence that a corrosive environment had been recently active on the drywell exterior or the epoxy coating in the sand bed region.

Q21. What do the 2006 UT results show about whether remaining thicknesses of the shell exceeds AmerGen's UT acceptance criteria?

A21. (Ashar) A review of the 106 UT thickness measurements in the locally thinned areas made during the October 2006 outage, in general, indicated that the metal thicknesses in these areas were lower than those in 1992. *See* AmerGen Letter to NRC (Dec. 3, 2006) (AmerGen Exhibit 12). AmerGen attributed the lower metal thickness as largely due to using a more accurate UT instrument and the procedure used to take the measurements, which involved moving the instrument within the locally thinned areas to locate the minimum thickness in the area (SER at 3-138). However, a review of the data attached to AmerGen's December 3 letter (*see* SER at 3-424) indicated that the measurements did not exceed the acceptance criteria for the locally thinned areas**.** Thus, the results of the 2006 UT measurements do not indicate any significant corrosion that would challenge the integrity of the drywell shell. *See* SER at 3-142 to 3-143.

Q22. What is the corrosion rate in the sand bed region, including uncertainties related to its determination?

A22. (Ashar) AmerGen has asserted, based on the comparison of the UT measurements in October 2006, and earlier UT measurement data, that the drywell corrosion in the sand bed area has been arrested. *See, e.g.***,** SER at 3-126. AmerGen, however, has described ten sources of uncertainties associated with UT measurements of the drywell shell (e.g. UT instrumentation, drywell surface roughness, probe location repeatability, UT probe rotation, temperature effects, NDE technician, UT unit setting, etc.) and its plans to address each source of uncertainty through implementation of proper procedures and training. *See* SER at 4-53 to 4-55. Between 1986 and 1992, the wall thickness loss at the thinnest located was reported to be 70 mils, resulting in linear corrosion rate of 12 mils/year. SER at 4-43.

As indicated on SER pages 4-59 and 4-60, the Staff evaluated the process used by AmerGen related to the UT measurements taken after the epoxy coating was applied. Initial locations identified in 1986 and 1987 where corrosion loss was most severe were selected for repeat inspection over time to measure corrosion rates. For locations where the initial investigations found significant wall thinning, new wall thickness were measured by UT at 49 points in 6" x 6" area, and verified for compliance with the minimum required wall thickness criteria. A statistical analysis was then performed of this dataset, and the mean value was compared to the previously calculated mean values at this location. A linear regression analysis of the old and new values was then performed to determine the slope and 95% upper and lower confidence intervals. For a non-zero slope, the slope of the line represents the corrosion rate at this location. The lower 95% confidence interval was then projected into the future and compared with the required minimum wall thickness criteria.

The use of the lower 95% confidence interval in projecting the future thicknesses, and the requirement that the thickness acceptance criteria are met, is consistent with the ASME Subsection IWE requirements for evaluating the UT results. The Staff concluded that the use of this process is acceptable for assessing the future corrosion rate. *See* SER at 4-60.

As previously noted, October 2006 outage results confirmed that the epoxy coating in the sand bed area has been effective in reducing corrosion in this area and indicated a corrosion rate of about 2 mils per year based on the wall thinning in the trenches. *See* SER at 3-424**.** When this corrosion rate is applied to the lowest average thickness of 0.8 inch for four years, the average thickness would reduce to 0.792 inch, which would be higher than the average minimum required thickness of 0.736 inch.

Q23. What is the Staff's position regarding the necessity for UT monitoring of the Oyster Creek drywell shell when visual inspection results for the epoxy coating do not identify any evidence of deterioration of the epoxy coating?

A23. The Staff position is that UT monitoring in the sand bed region is necessary even when visual inspection results for the epoxy coating satisfy the acceptance criteria of ASME Section XI, Subsection IWE-3512 due to (1) the inability to make a definitive assessment regarding the uncertainties related to corroded areas, (2) only three reliable points of metal thickness data, and (3) the unknown duration of the effectiveness of the epoxy coating in protecting the sand bed region metal surfaces. Thus, both the VT-1 examination of the epoxy coating and UT monitoring should continue throughout the extended period of operation as committed by AmerGen in Commitment 27, Item 21.

Q24. What is the Staff's conclusion regarding whether the aging management program for the drywell shell is adequate for the license renewal period?

A24. The results of the 2006 outage inspection indicate that AmerGen corrective actions (removal of the sand and application of epoxy coating) have been effective in managing corrosion of the drywell shell. AmerGen's Aging Management Program includes commitments listed in Appendix A of the SER to periodically monitor corrosion in the sand bed region of the drywell shell, identify the extent of additional degradation, perform additional UT measurements and compare thickness differentials, report statistically significant corrosion to the NRC, and perform an operability determination and justification for operation until the next inspection.

Based on the condition of the Oyster Creek drywell shell in the sand bed region during the 2006 outage, the AmerGen Aging Management Program, as enhanced by commitments to perform UT inspections every other outage (as required by proposed license condition), provides reasonable assurance that drywell shell integrity (and the intended function of the drywell) will be maintained during the period of extended operation. Thus, AmerGen's Aging Management Program will adequately manage the condition of the drywell shell during the proposed license renewal period.

Hansraj G. Ashar
Statement of Professional Qualifications

CURRENT POSITION:

Senior Structural Engineer   Division of Engineering, Office of Nuclear Reactor Regulation

U.S. Nuclear Regulatory Commission
Rockville, MD

EDUCATION

Bachelor of Civil Engineering, Gujarat University, India
Masters Degree in Civil-Structural Engineering, 1958, University of Michigan, Ann Arbor, MI

Registered Professional Engineer in the States of Ohio and Maryland.

EXPERIENCE

For the last 33 years, I have been working as a Structural engineer/Sr. Structural Engineer with the U.S. Nuclear Regulatory Commission in review of the plant licenses, standards development, containment related research activities and license renewal activities.
For the first eleven years of my career, I have worked as a Bridge Engineer in the States of Ohio, New Jersey; and in Wiesbaden Germany on designing steel, reinforced and prestressed concrete bridges. The next five years, I worked as a Lead Civil Engineer on developing design documents and procurement specifications for nuclear power plants, namely, Three Mile Island, Unit 2, Forked River, and Oyster Creek.

I represent NRC in a number of Standards Developing Organizations, namely, American Society of Mechanical Engineers (ASME), American Concrete Institute, and American Institute of Steel Construction on several committees developing standards related to the nuclear power plant structures. I am a fellow member of the American Concrete Institute, and the American Society of Civil Engineers.

REGULATORY DOCUMENTS (Principal Author):

Information Notices

IN 93-53	Effects of Hurricane Andrew on Turkey Point Nuclear Generating Station and Lessons Learned, April 1994
IN 95-49	Seismic Adequacy of Thermo-Lag Panels, October 1995 Supplement 1: Seismic Adequacy of Thermo-Lag Panels, December 1997
IN 97-10	Liner Plate Corrosion in Concrete Containments, March 1997
IN 97-11	Cement Erosion from Containment Subfoundation at Nuclear Power Plants, March 1997

IN 97-22 Failure of Welded Steel Moment-Resisting Frames During the Northridge Earthquake, April 1997

IN 97-29 Containment Inspection Rule, May 1997

IN 98-26 Settlement Monitoring and Inspection of Plant Structures Affected by Degradation of Porous Concrete Subfoundation, July 1998

IN 99-10 Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments, April 1999

IN 06-01 Torus Cracking in a BWR Mark-I Containment, January 2006

ISG 06-01 Aging Management Program for Inaccessible Areas of BWR Mark-I Containment Drywell shell, September 2006

Inspection Procedures

IP 62002 Inspection of Structures, Passive Components, and Civil Engineering Features at Nuclear Power Plants, Dec. 1996

IP 62003 Inspection of Steel and Concrete Containments at Nuclear Power Plants, June 1997

Regulatory Guides

RG 1.35 Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments. Rev. 1 (1974), 2 (1976), 3 (1990)

RG 1.35.1 Determining Prestressing Forces for Inservice Inspection of Prestressed Concrete Containments: Draft (1979), final (1990)

RG 1.90 Inservice Inspection of Prestressed Concrete Containments with Grouted Tendons: (1977).

RG 1.107 Qualification of Cement Grouting for Prestressing Tendons in Prestressed Concrete Containments: (1977)

RG 1.136 Materials, Construction and Testing of Concrete Containments (Endorsement of ASME Section III/Div. 2 (or ACI 359): (1981)

RG 1.142 Safety-Related Concrete Structures for Nuclear Power Plants (Other than Reactor Vessels and Containments): (1981)

Technical Support to the principal coordinators of 10 CFR 50.55a, (Codes and Standards) Revisions on endorsing Subsections IWE/IWL (ISI of Containments) of the ASME Code: 1994 to Present

PROFESSIONAL AND COMMUNITY ACTIVITIES

Participation in National and International Standards Organizations

Member of the following NSO and INSO Committees:

- American Institute of Steel Construction (AISC)
  Chairman: Nuclear Specification Committee (AISC/ANSI N690)
  Member: Building Specification Committee
  Advisory: Seismic Provisions Committee
- American Concrete Institute (ACI) 349 Committees
  Member: Main committee
  Member: Subcommittee 1 on General Requirements, Materials and QA
  Member: Subcommittee 2 on Design
- American Society of Mechanical Engineers (ASME):
  Member: Working Group on Inservice Inspection of Concrete and Steel Containments (Subsections IWE and IWL of ASME Section XI Code)
  Member: ASME/ACI Joint Committee on Design, Construction, Testing and Inspection of Concrete Containments and Pressure Vessels
- Member: RILEM Task Committee 160-MLN: Methodology for Life Prediction of Concrete Structures in Nuclear Power Plants
- Member: Federation Internationale du Beton (FIB) Task Group 1.3: Containment Structures
- Consultant to IAEA on Concrete Containment Database (2001 to 2005)

PROFESSIONAL MEMBERSHIPS

Professional Engineer: State of Ohio, State of Maryland
Fellow - American Concrete Institute
Fellow - American Society of Civil Engineers
Professional Member - Post-tensioning Institute

COMMUNITY ORGANIZATIONS - SERVICES

Member- Montgomery County Energy and Air-Quality Advisory Committee (1995 to 2001)
Science Fair Judge (Montgomery County) - 1994-2001
Member-Architectural Committee – Hickory Crest, Columbia, Association

Peer reviewer of number of papers to be published in ASCE Material Journal, NED Periodicals, and ACI International.

PUBLICATIONS/PRESENTATIONS

1. Ashar, H., Terao, D., Imbro, E.: “Reliability of Containment and Risk-Informed Decision Making – A Perspective,” Presented at SMiRT17 International Conference in Prague, Czech Republic, August 2003.

2. Ashar, H., Imbro, E, Terao, D.: Integrated Leak Rate Testing of Containments - A Regulatory Perspective, Presented by Eugene Imbro at ICONE11 in Tokyo, Japan, April 2003.

3. Ashar, H.: Inspection of Containment Structures in the U.S.A. Presented at the 16th International Conference on Structural Mechanics in Reactor Technology, Washington DC. August 12-17, 2001.

4. Kotzalas, M., Ashar, H.: Regulatory Issues Involved in the Use of the ASME XI, IWE/IWL, Presented at the ASME Pressure Vessel and Piping Conference, Atlanta, GA. July 2001.

5. Ashar H., Kotzalas, M.: Implementation of Containment Inspection Rule, 10 CFR Part 50.55a, Presented at the ASME Pressure Vessel and Piping Conference, Atlanta, GA. July 2001.

6. Ashar, H.: Implications of Concrete Structure Degradations in Nuclear Power Plants, Proceedings of the International RILEM Conference on Life Prediction and Aging Management of Concrete Structures, Cannes, France, October 16-18, 2000.

7. Ashar, H., Bagchi, G.: "Monitoring Degradation of Concrete Structures in U.S. Nuclear Power Plants," Proceedings of the 8th International Conference (Sponsored by RILEM) on "Life Management and Aging Management of Concrete Structures," Bratislava, Slovakia, July 1999.

8. Ashar, H., Bagchi, G.: "Implementation of Maintenance Rule for Structures," Proceedings of the 7" symposium on Current Issues Related to Structures, Systems, and Piping, North Carolina State University, Raleigh, NC, December 1998 (Published in Nuclear Engineering and Design in Nov. 1999).

9. Ashar, H., Costello, J., Graves, H.: "Prestress Force Losses in Containments of U.S. Nuclear Power Plants," Proceedings of the Joint WANO-PCIOECD-NEA Workshop on Prestress Loss in Nuclear Containments, Poitier, France, August 1997.

10. Ashar, H., Bagchi G.: "Safety Related Nuclear Power Plant Structures - Assessment of Inservice Conditions," NUREG 1522, U.S. Nuclear Regulatory Commission, Washington D.C., 20555, May 1995.

11. Ashar, H., Jeng, D.: "Degradation of Passive Components in U.S. Nuclear Power Plants," Proceedings of the 6th Symposium on Current Issues Related to Structures, Systems, and Piping, North Carolina State University, Raleigh, NC, December 1996.

12. Ashar, H., Jeng, D.: "Performance of Structures in Nuclear Power Plants," Paper X/2, Proceedings of the 5th Symposium on Current Issues Related to Structures, Systems, and Piping, Orlando, Fl., December 1994.

13. Ashar, H., Naus, D., Tan, C. P.: "Prestressed Concrete in U.S. Nuclear Power Plants," Concrete International, American Concrete Institute, Detroit, Michigan, Part I in May 1994, Part 2 in June 1994.

14. Jeng, D., Bagchi, G., Ashar, H.: "Structural Issues Related to Containment Performance in Advanced Reactors," Proceedings of the Second ASME/JSME Conference on Nuclear Engineering, San Francisco, CA, March 1993.

15. Ashar, H., Tan, C. P.: "Inservice Performance of Containment Structures - U.S. Experience," Proceedings of the 11th Conference of Structural Mechanics in Reactor Technology (SMIRT), Tokyo, Japan, August 1991.

16. Tan, C. P., Ashar, H.: "Modifications of Concrete Containments for Steam Generator Replacement-Regulatory Considerations," Proceedings of SMIRT 11th, Tokyo, Japan, August 1991.

17. Ashar, H., Jeng, D.: "Effectiveness of Inservice Requirements for Prestressed Concrete Containments," Proceedings of the 2nd International Conference on Containment Design and Operation, Toronto, Ontario, Canada, October 1990.

18. Ashar, H., Degrassi, G.: "Design and Analysis of Free standing Spent Fuel Racks in Nuclear Power Plants," Proceedings of the 10th SMIRT Conference, Anaheim, CA., August 1989.

19. Bagchi, G., Jeng. D., Ashar, H.: "Proposed Modifications of NRC's Standard Review Plan for Seismic Analysis," Proceedings of the 2nd Symposium on Current Issues Related to NPP Structures, Systems, and Piping, Orlando, Fl., Dec. 1988.

20. Ashar, H., Jeng, D.: “Spent Fuel Storage - A Regulatory Perspective," Presented at 1988 ASME Joint Power Generation Conference, Philadelphia, Pa. September 1988.

21. Richardson, J., Ashar, H.: "Regulatory Perspective on Containment Performance," Presented at MITI/NRC Conference on Nuclear Technology, Tokyo, Japan, Dec. 1987.

22. Ashar, H., Naus, D.: "Overview of the Use of Prestressed Concrete in U.S. Nuclear Power Plants," Nuclear Engineering and Design, Val. 75, North Holland Publishing Company, August 1983.

23. Dougan, J., Ashar, H.: "Evaluation of Grease Performance in Prestressed Concrete Containments," Proceedings of 6th SMIRT Conference, Chicago, 11. August 1983.

James A. Davis, Ph. D
Statement of Professional Qualifications

CURRENT POSITION:

Senior Materials Engineer	Division of License Renewal, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Rockville, MD

EDUCATION:

B. Met. E., The Ohio State University, 1965, Metallurgical Engineering
M.S., The Ohio State University, 1965, Metallurgical Engineering
Ph.D., The Ohio State University, 1968, Metallurgical Engineering

SUMMARY:

Over 39 years of experience in material engineering with over 20 years of experience in the nuclear power industry. Significant experience in the following areas:

- Materials Engineering
- Corrosion and Control
- Protective Coatings and Linings
- Welding and Special Repair Processes
- License Renewal
- Nuclear Facilities Audits
- Allegations
- Reviews of Navy Submarine Power Plant Designs
- Quality Assurance
- ASME Code Committees
- ASTM D-33 Committee on Coatings for Power Generation Facilities

EXPERIENCE:

U.S. Nuclear Regulatory Commission, 11/11/1990 - Present

11/13/2005 to Present - Senior Materials Engineer, Division of License Renewal, Office of Nuclear Regulatory Research

- Audit Team Leader for the license renewal safety audit at the Pilgrim Nuclear Power Station

- Audit Team Member for the license renewal safety audit at the Oyster Creek Generating Station

12/15/2001 - 11/13/ 2005 – Senior Materials Engineer in the Division of Engineering Technology, Office of Nuclear Regulatory Research

- Program Manager on the Steam Generator Tube Integrity Program overseeing work conducted at Argonne National Laboratory

- Acting Program Manager for Non-Destructive Examination research at Pacific Northwest National Laboratory

11/11/1990 - 12/15/2001 - Technical Reviewer in the Materials and Chemical Engineering Branch, Chemical Engineering and Metallurgy Section, Division of Engineering, Office of Nuclear Reactor Regulation.

- Coatings for nuclear power plants,

- License renewal for Calvert Cliffs, Oconee, Arkansas Nuclear One, Hatch, and Turkey Point.

- Threaded fastener issues (such as stress corrosion cracking, boric acid corrosion, and fatigue),

- chemical decontamination,

- Boiling Water Reactor internals cracking,

- pump and valve internals cracking,

- pipe integrity issues,

- corrosion behavior for dry cask storage, and interaction of coatings with spent fuel water,

- Coordinated the responses to a generic letter on containment coatings for nuclear power plants.

- NRC representative to ASTM D-33 on coatings for power generation facilities.

- Member of the Board of Directors for the National Board of Registration for Nuclear Safety Related Coating Engineers & Specialists.

- Member of ASME on Welding and Special Repair Processes.

- Member of an Augmented Inspection Team at Palisades on fuel handling problems, Point Beach on the hydrogen burn as a result of interactions between borated water and the inorganic Zinc coating during dry cask loading operations and Davis-Besse on the Boric acid corrosion of he vessel head.

- Contract Technical Monitor and Project Officer for numerous contracts at Brookhaven National Labs.
- Technical reviewer for the design of the Navy Seawolf Submarine and the Virginia Class Submarine
- Reviewer on the DOE project to produce tritium in a commercial reactor (Watts Bar)
- Numerous presentations to senior NRC management including the Chairman, the Executive Director for Operations, the Committee to Resolve Generic Issues, and the Advisory Committee on Reactor Safety and Safeguards.
- Testified before Representative Dingle's staff on the safety of fasteners in nuclear power plants as a result of concerns raised by a private citizen.

Polyken Division of the Kendall Company. Senior Research Associate, 1981 – 1990:

Responsible for Technical Marketing for the pipeline coating division providing technical data and reports to domestic and international customers. Company representative to the National Association of Corrosion Engineers, the American Water Works Association coatings committees, and ASTM coating committees.

Arthur D. Little, Senior Consultant, 1979 - 1981:

Consultant to DOE on Defense Nuclear Waste issues and Waste Tank corrosion issues. Consultant on numerous commercial contracts on corrosion, coating, metallurgical, and plating issues.

Allied Tube and Conduit Corp., Director of Research, 1978-1979:

Responsible for research and development for metallurgical tube forming, welding, chemical cleaning of steel, galvanizing, surface treatment and coating of electrical conduit, fence posts, and specialty tubing. Responsible for Quality Assurance and Process Control.

Allegheny Ludlum Steel Corp., Research Specialist, 1976-1978:

Responsible for customer service for use of stainless steels in corrosive service. Responsible for conducting failure analysis. Conducted research on corrosion mechanisms for stainless steels.

Bell Aerospace Company, Senior Research Scientist, 1970-1976:

Program Manager on numerous Navy sponsored programs involving corrosion of aluminum alloys, stainless steels, and titanium alloys in high velocity sea water for the Navy's high performance ships program. Conducted research on corrosion fatigue, stress corrosion, and fouling in sea water. Conducted research on the compatibility of rocket fuels and oxidizers with fuel handling equipment.

U.S, Steel Corporation, Senior Research Engineer, 1968-1970:

Conducted research on the mechanism of pitting/crevice corrosion, stress corrosion cracking, hydrogen embrittlement, and intergranular corrosion using electrochemical techniques, transmission electron microscopy, optical microscopy, and scanning electron microscopy.

Mark Hartzman, Ph. D.
Statement of Professional Qualifications

CURRENT POSITION:

Senior Mechanical Engineer
Mechanical and Civil Engineering Branch (EMCB)
Division of Engineering
Office of Nuclear Reactor Regulation

EDUCATION:

- B.**S.** Mechanical Engineering, The City College of New York, New York, N. Y., 1959.

- MS Mechanical Engineering, University of Washington, Seattle, WA, 1963. Major: Engineering Mechanics.

- Ph. D., Mechanical Engineering, University of California, Davis, CA, 1970. Major: Engineering Mechanics.

SUMMARY:

Over 48 years of experience in Engineering Mechanics and Structural Analysis. Over 32 years experience in Nuclear Regulatory review and evaluation. Significant review experience in the following areas:

- Finite element analysis - solid mechanics, statics and dynamics
- Structural seismic analysis methodology
- Structural computer programs
- Piping analysis methodology and criteria
- ASME Section III Code design criteria
- License renewal

EXPERIENCE:

U.S. Nuclear Regulatory Commission, 06/75 - present

Wide variety of assignments over this time period. Representative assignments have consisted or consist of the following:

- Review of a wide variety of license amendment requests, requiring in-depth technical evaluation of licensee calculational methodology and procedures.

- Evaluation of licensee responses to I&E Bulletin 79-07, "Seismic Stress Analysis of Safety Related Piping." Co-author of reports NUREG/CR 1677, "Piping Benchmark Problems", Volumes 1 and 2.

- Development of acceptance criteria for I&E Bulletin 79-02, "Pipe Support Base Plate Design Using Concrete Expansion Anchor Bolts."

- Evaluation of industry acceptance criteria and plant responses to I&E Bulletin 88-08 “Thermal Stresses in Piping Connected to Reactor Coolant Systems.”

- Evaluation of license renewal requests in the area of time limited aging analysis of ASME Section III metal components (metal fatigue) for the following plants:

  Palisades, St. Lucie
  Browns Ferry, V. C. Summer
  Brunswick, ANO-2

- Evaluation of allegations:

  Example: Deficiencies in piping and base plate design at the Diablo Canyon NPP, 1982-1984.

- Revision and updating of the Standard Review Plan within the scope of the EMCB.

- Evaluation of ASME Section III code cases for acceptance and listing in Regulatory Guide 1.84.

- Assistance to NRC Regions with technical resolution of inspection reports and differing professional opinions (DPOs):

  Example: Fermi HVAC duct safety under tornado loading. Resulted in NRC Regulatory Issue Summary (RIS) 2006-23, “Post-tornado Operability of ventilating and Air Conditioning Systems Housed in Emergency Diesel generating Rooms.”

  Example: In 2006, as a member of a Region II Differing Professional Opinion DPO panel, performed the technical evaluation of a DPO regarding Oconee pipe whip structural integrity.

- Participation in ASME Section III Code working groups and committees since 1974. As the NRC representative, participated or currently participate in the following groups:

  Task Group on Faulted Conditions
  Working Group on Dynamic and Extreme Loading Conditions
  Working Group on Vessels (current)
  Working Group on Methods Development (current)

The Lawrence Livermore National Laboratory, Livermore, CA, 1973-1975

(On loan to the USAEC, Mechanical Engineering Branch (MEB))
- Review of new plants construction license applications.
- Assistance with development of the Standard Review Plan within the scope of

the MEB.

- Review of ASME Code Section III faulted condition acceptance criteria.

The Lawrence Livermore National Laboratory, Livermore, CA, 1963-1973.

Computer-based design and analysis of equipment used in testing of nuclear weapons. Ph. D. dissertation based on this work.

The Boeing Company, Seattle, WA, 1959 - 1963

- Design and stress analysis of pilotless aircraft and helicopter engines.

- Research in the fabrication of aircraft components using explosives. MS thesis based on this work.

Timothy L. O'Hara
Statement of Professional Qualifications

CURRENT POSITION:

Reactor Inspector U.S. Nuclear Regulatory Commission, Region 1 Office,
Division of Reactor Safety, Plant Support Branch 2

EDUCATION:

Bachelor of Science in Physics, 1970, Saint Francis University, Loretto, PA
U.S. Naval Officer Candidate School, 1971, Newport, RI
U.S. Naval Nuclear Power Program, 1972, Bainbridge, MD and Windsor, CT
Master of Science in Engineering Management, 1980, University of Pittsburgh, Pittsburgh, PA
Master of Business Administration, 1988, Temple University, Philadelphia, PA

EXPERIENCE:

U.S. Nuclear Regulatory Commission, June 2002 - Present

Reactor Inspector, Region I, Plant Support Branch 2, King of Prussia, PA, October 2005 to Present
Conduct engineering inspections and assess licensee performance at commercial nuclear power plants throughout the northeast US. Inspections include Inservice Inspections, Plant Component Replacement Inspections (Steam Generators, Pressurizers, and Reactor Vessel Closure Heads), License Renewal Aging Management Inspections, Plant Modifications, Problem Identification and Resolution, Resident Inspector coverage, and Safety System Design Inspections. Training in ASME Code, Eddy Current Testing, Fracture Mechanics, welding techniques and Construction Procedures.

Reactor Inspector, Region I, Engineering Branch I, King of Prussia, PA, October 2004 - September 2005
Conduct engineering inspections and assess licensee performance at commercial nuclear power plants throughout the northeast US. Inspections include Plant Modifications, Problem Identification and Resolution, Fire Protection, In Service Inspection, Resident Inspector coverage, and Safety System Design Inspections. Training in Digital Circuits, Electrical System Coordination and Short Circuit Calculations.

Reactor Inspector, Region I, Electrical Branch, King of Prussia, PA, June 2002 - September 2004
Conduct engineering inspections and assess licensee performance at commercial nuclear power plants throughout the northeast US. Inspections include Plant Modifications, Problem Identification and Resolution, Fire Protection, In Service Inspection, Resident Inspector coverage, and Safety System Design Inspections. Training in BWR and PWR plant design and operation.

<u>Completed the following inspections during the past five years:</u>

Salem U1, Inservice Inspection, September 2004, Team Lead
Indian Point U2, Inservice Inspection, November 2004, Team Lead
Ginna, Inservice Inspection, March 2005, Team Lead
Salem U2, Inservice Inspection, April 2005, Team Lead
Beaver Valley U1, Stream Generator Replacement, January - June 2006, Team Lead
Beaver Valley, SSDI, August 2002
Calvert Cliffs, Modifications & 50.59 Inspection, December 2002
Vermont Yankee, Modifications & 50.59 Inspection, April 2003
Millstone U2 & U3, Modifications & 50.59 Inspection, June 2003
Nine Mile Point U1 & U2, Modifications & 50.59 Inspection, August 2003
Salem, EDG Turbocharger Special Inspection, September 2003
Fitzpatrick, SSDI, October 2003
Salem U1, Inservice Inspection, September 2003
Ginna, Triennial Fire Protection Inspection, November 2003
Oyster Creek, Triennial Fire Protection Inspection, January 2003
Indian Point U2, Triennial Fire Protection Inspection, January 2004
Vermont Yankee, Triennial Fire Protection Inspection, December 2004
Indian Point U3, Triennial Fire Protection Inspection, February 2005
Ginna, License Renewal Inspection, Scoping & Screening, August 2003
Millstone, License Renewal Aging Management Inspection, September 2004
Indian Point U2, Modifications & 50.59 Inspection, January 2005
Nine Mile Point U1 & U2, License Renewal Aging Management Inspection, February 2005
Oyster Creek, License Renewal Aging Management Inspection, March 2006
Oyster Creek PI&R Team Inspection, May 2004
Hope Creek, PI&R Team Inspection, December 2005
Pilgrim, License Renewal Aging Management Inspection, September 2006
Oyster Creek License Renewal Commitment Inspection, October 2006
Vermont Yankee, License Renewal Aging Management Inspection, February 2007
Calvert Cliffs, PI&R Sample (460v breakers), June 2004
Salem PI&R Sample (CC-17 valve), June 2004
Ginna PI&R Sample (Human Performance), July 2006
Salem PI&R Sample (Auxiliary Building Ventillation - Charcoal Filters), June 2005
Peach Bottom PI&R Sample (Corrective Actions), July 2006
Salem PI&R Sample (Corrective Actions), September 2006
Oyster Creek, Resident Backfill, July 2003
Salem Resident Inspector Backfill, June 2004
Hope Creek, Inservice Inspection, April 2006
Peach Bottom U2 & U3, PI&R Sample (Torus Corrosion), July 2006
Salem U2 Inservice Inspection, October 2006
Susquehanna U1, Inservice Inspection, March 2007
Salem U1, Inservice Inspection, April 2007

NRC TRAINING COURSES COMPLETED:

Power Plant Engineering
Effective Communication For NRC Inspectors
Media Training Workshop
Expectations For Inspectors
PRA Basics For Regulatory Applications
Westinghouse 100 Technology
Gathering Information For Inspectors
PRA Techniques and Regulatory Perspectives
Root Cause/Incident Investigation Workshop
Allegations Training - Classroom
Ethics Orientation
Conducting Inspections
GE BWR/4 Technology
GE BWR/4 Advanced Technology
GE BWR/4 Simulator
Field Techniques And Regulatory Processes
Ethics Laws & Rules For Employees
Fire Protection For Power Plants
Response Technical Manual Training
SNE 594, Westinghouse Station Nuclear Engineers Training
Improving Employment Applications
Industrial & Commercial Power Distribution Systems
Digital I & C Training
Low Voltage Protection Course
Eddy Current Testing
Eddy Current & UT Testing of RV Head Penetrations, Wesdyne
GE BWR/4 Simulator Refresher Training
American Concrete Institute Seminar, Inspecting Concrete Structures
Fracture Mechanics Training
Construction Inspector Training
ASME B&PV Code, Section VIII

Denton Vacuum, LLC, June 1997 to February 2002

Operations Manager, Vacuum Equipment Division, Moorestown, NJ
Responsible for material management, manufacturing, assemble and testing of complex vacuum deposition (thin film) equipment and systems for this privately held company.

Scott Specialty Gases, September 1993 to January 1997

General Manager, High Pressure Technology - Plumsteadville, PA

Total business responsibility for the turnaround of high pressure cylinder manufacturing and startup of a custom equipment product line. Establishment of specialty innovative, custom gas handling and distribution equipment. Sales, manufacturing, new product development, and customer service responsibility.

<u>Westinghouse Electric Corporation, December 1975 to August 1993</u>

<u>District Manager</u>, Philadelphia Operations Center - 1989-1993
Total business responsibility for the Engineering Services Division's Philadelphia Region. Performed commercial electrical services and electrical equipment installation. Responsible for sales, customer service, and engineering services for all industrial sectors.

<u>Manager</u>, Nuclear Services Operations, Moorestown, NJ - 1985-1989
Total P&L responsibility for custom manufacturing decontamination and mobile cleaning services. Directed a staff of 5 managers and 150 technicians. Integrated an acquired subsidiary company into an existing corporate division.

<u>Manager</u>, Mechanical Projects, Monroeville, PA - 1981-1985
Field Service responsibility for reactor internals repairs for commercial power plants. Split pin replacement, reactor upflow conversion, spent fuel rack replacement, foreign object search and retrieval, and miscellaneous mechanical repairs. Extensive work with utility representatives, Westinghouse Engineering and research groups. Managed 22 field engineers and 75 field service technicians

<u>Site Manager</u>, Steam Generator Replacement, Surry, VA - 1979-1981
Westinghouse site representative for SG replacement. Responsible for daily contact between utility and Westinghouse engineering, manufacturing and field service resources. Extensive involvement in mechanical problems, welding issues, and plant startup.

<u>Nuclear Fuel Licensing Engineer</u>, Monroeville, PA - 1977 -1979
Lead the Westinghouse effort on reload core licensing. Extensive involvement with utilities and internal Westinghouse Fuel and Engineering Divisions.

<u>Senior Field Service Engineer</u>, Churchill, PA - 1975-1977
Conducted SG eddy current inspections, SG sludge lancing, and SG weld repairs at Westinghouse commercial nuclear power plant. Extensive work with utility representatives and Westinghouse Engineering and Research groups.

<u>U. S. Navy, September 1970 to November 1975</u>

Completed Navy Basic Training and Electronic Technician Class A Training. Attended Officer Candidate School and Naval Nuclear Power Training. Served as a junior engineering office on board USS Seahorse and USS Sam Houston. Served as Electrical Officer, Damage Control Assistant, Ship's Diving Officer, Subsafe Officer, Engineering Plant Watch Officer. Completed extensive ship overhaul and refueling.

<u>PROFESSIONAL MEMBERSHIPS:</u>

American Society of Mechanical Engineers
American Nuclear Society

Beta Gamma Sigma
Society of Manufacturing Engineers

HONORS AND AWARDS:

Frank Castelli Academic Scholarship
Saint Francis University Physics Award
Officer Candidate School, Distinguished Naval Graduate
Temple University Executive MBA Selection, Westinghouse Electric Corporation
Beta Gamma Sigma Distinguished Scholar, Temple University
NRC Team Award, December 2002, Salem Special Inspection
NRC Performance Award, Spring 2003
NRC Performance Award, December 2004
NRC Performance Award, December 2005
NRC Performance Award, December 2006

Staff Exhibit 1

Safety Evaluation Report
Related to the License Renewal of Oyster Creek Generating Station

Docket No. 50-219

AmerGen Energy Company, LLC

Manuscript Completed: March 2007
Date Published: April 2007

Division of License Renewal
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the license renewal application (LRA) for Oyster Creek Generating Station (OCGS), as filed by AmerGen Energy Company, LLC (AmerGen or the applicant). By letter dated July 22, 2005, AmerGen submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the OCGS operating license for an additional 20 years. The NRC staff (the staff) prepared this report, which summarizes the results of its safety review of the LRA for compliance with the requirements of Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." The NRC license renewal project manager for the OCGS license renewal review is Donnie J. Ashley. Mr. Ashley can be contacted by telephone at 301-415-3191 or by electronic mail at dja1@nrc.gov. Alternatively, written correspondence may be sent to the following address:

License Renewal and Environmental Impacts Program
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001
Attention: Donnie J. Ashley, Mail Stop 0-11F1

In its July 22, 2005, submittal letter, the applicant requested renewal of the operating license issued under Section 104b (Operating License No. DPR-16) of the Atomic Energy Act of 1954, as amended, for OCGS for a period of 20 years beyond the current license expiration date of midnight April 9, 2009. OCGS is located in Lacey Township, Ocean County, New Jersey, approximately two miles south of the community of Forked River, two miles inland from the shore of Barnegat Bay, and nine miles south of Toms River, New Jersey. The NRC issued the OCGS construction permit on December 15, 1964, and the OCGS operating license on July 2, 1991. OCGS is a single unit facility with a single-cycle, forced-circulation boiling water reactor (BWR)-2 and a Mark 1 containment. The nuclear steam supply system was furnished by General Electric (GE) and the balance of the plant was originally designed and constructed by Burns & Roe. OCGS's licensed power output is 1930 megawatt thermal with a gross electrical output of approximately 619 megawatt electric. The updated final safety analysis report (UFSAR) contains details concerning the plant and the site.

The license renewal process consists of two concurrent reviews: (1) a technical review of safety issues and (2) an environmental review. The NRC regulations found in 10 CFR Parts 54 and 51, respectively, set forth the requirements against which license renewal applications are reviewed. The safety review for the OCGS license renewal is based on the applicant's LRA and responses to the staff's requests for additional information. The applicant supplemented its LRA and provided clarifications through its responses to requests for additional information in audits, meetings, and docketed correspondence. Unless otherwise noted, the staff reviewed and considered information submitted through December 15, 2006, and after this date on a case-by-case basis depending on the stage of the safety review and on the volume and complexity of the information. The public may view the LRA and all pertinent information and materials, including the UFSAR, at the NRC Public Document Room on the first floor of One

White Flint North, 11555 Rockville Pike, Rockville, MD 20852-2738 (301-415-4737 / 800-397-4209), and at the Lacey Branch - Ocean County Library, 10 East Lacey Road, Forked River, NJ 08731. In addition, the public may find the LRA, as well as materials related to the license renewal review, on the NRC Web Site at www.nrc.gov.

This SER summarizes the results of the staff's safety review of the LRA and describes the technical details considered in evaluating the safety aspects of the proposed operation for an additional 20 years beyond the term of the current operating license. The staff reviewed the LRA in accordance with NRC regulations and the guidance of NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), dated September 2005.

SER Sections 2 through 4 address the staff's review and evaluation of license renewal issues considered during the review of the application. Section 5 is reserved for the report of the Advisory Committee on Reactor Safeguards (ACRS). Conclusions of this report are presented in Section 6.

SER Appendix A contains a table that identifies the applicant's commitments for the renewal of the operating license. Appendix B provides a chronology of the principal correspondence between the staff and the applicant on the review of the application. Appendix C is a list of the principal contributors to this SER. Appendix D is a bibliography of the references in support of the review.

In accordance with 10 CFR Part 51, the staff prepared a draft, plant-specific supplement to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)". This supplement discusses the environmental considerations for renewal of the OCGS license. The staff issued Draft Supplement 28 to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Regarding Oyster Creek Generating Station, Draft Report for Comment," in June 2006.

1.2 License Renewal Background

Pursuant to the Atomic Energy Act of 1954, as amended, and NRC regulations, operating licenses for commercial power reactors are issued for 40 years. These licenses can be renewed for up to 20 additional years. The original 40-year license term was selected on the basis of economic and antitrust considerations rather than on technical limitations; however, some individual plant and equipment designs may have been engineered for an expected 40-year service life.

In 1982, the staff anticipated interest in license renewal and held a workshop on nuclear power plant aging. This workshop led the staff to establish a comprehensive program plan for nuclear plant aging research. With the results of that research, a technical review group concluded that many aging phenomena are readily manageable and pose no technical issues that would preclude life extension for nuclear power plants. In 1986, the staff published a request for comment on a policy statement that would address major policy, technical, and procedural issues related to license renewal for nuclear power plants.

In 1991, the staff published the license renewal rule in 10 CFR Part 54 (the Rule), (56 FR 64943 dated December 13, 1991). The staff participated in an industry-sponsored demonstration program to apply the Rule to a pilot plant and to gain experience necessary to develop implementation guidance. To establish a scope of review for license renewal, the Rule defined age-related degradation unique to license renewal; however, during the demonstration program, the staff found that adverse aging effects that occur to plant systems and components are managed during the period of initial license. In addition, the staff found that the scope of the review did not allow sufficient credit for existing programs, particularly the implementation of the Maintenance Rule, which also manages plant-aging phenomena. As a result, the staff amended the Rule in 1995 (60 FR 22461 dated May 8, 1995). The amended Rule established a regulatory process simpler, more stable, and more predictable than the previous Rule. In particular, the staff amended the Rule to focus on managing the adverse effects of aging rather than on identifying age-related degradation unique to license renewal. The staff initiated these Rule changes to ensure that important systems, structures, and components (SSCs) will continue to perform their intended functions during the period of extended operation. In addition, the revised Rule clarified and simplified the integrated plant assessment process to be consistent with the revised focus on passive, long-lived structures and components (SCs).

In parallel with these efforts, the staff pursued a separate rulemaking effort and developed an amendment to 10 CFR Part 51 to focus the scope of the review of environmental impacts of license renewal and fulfill the NRC’s responsibilities under the National Environmental Policy Act of 1969.

1.2.1 Safety Review

License renewal requirements for power reactors are based on two key principles:

(1) The regulatory process is adequate to ensure that the licensing bases of all currently operating plants provide and maintain an acceptable level of safety, with the possible exception of the detrimental effects of aging on the functionality of certain SSCs, as well as a few other safety-related issues, during the period of extended operation.

(2) The plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term.

In implementing these two principles, 10 CFR 54.4 defines the scope of license renewal as including those SSCs (1) that are safety-related, (2) whose failure could affect safety-related functions, and (3) that are relied on for compliance with NRC regulations for fire protection, environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transient without scram (ATWS), and station blackout (SBO).

Pursuant to 10 CFR 54.21(a), an applicant for a renewed license must review all SSCs within the scope of the Rule to identify SCs subject to an aging management review (AMR). Those SCs subject to an AMR perform an intended function without moving parts or without a change in configuration or properties and are not subject to replacement based on a qualified life or specified time period. As required by 10 CFR 54.21(a), an applicant for a renewed license must demonstrate that the effects of aging will be managed in such a way that the intended function(s) of those SCs will be maintained, consistent with the current licensing basis (CLB), for the period of extended operation; however, active equipment is considered to be adequately monitored and maintained by existing programs. In other words, the detrimental effects of aging that may affect active equipment are more readily detectable and can be identified and corrected through routine surveillance, performance monitoring, and maintenance activities. The surveillance and maintenance activities programs for active equipment, as well as other aspects of maintaining the plant's design and licensing basis, are required throughout the period of extended operation.

Pursuant to 10 CFR 54.21(d), the LRA is required to include a UFSAR supplement with a summary description of the applicant's programs and activities for managing the effects of aging and an evaluation of time-limited aging analyses (TLAAs) for the period of extended operation.

License renewal also requires identification and updating of TLAAs. During the design phase for a plant, certain assumptions about the length of time that the plant can operate are incorporated into design calculations for several of the plant's SSCs. In accordance with 10 CFR 54.21(c)(1), the applicant must either show that these calculations will remain valid for the period of extended operation, project the analyses to the end of the period of extended operation, or demonstrate that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

In 2001, the staff developed and issued Regulatory Guide 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses." This regulatory guide endorses Nuclear Energy Institute (NEI) 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," dated March 2001. NEI 95-10 details an acceptable method of implementing the Rule. The staff also used the SRP-LR to review the application.

In the LRA, the applicant fully utilized the process defined in NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report," dated September 2005. The GALL Report provides the staff with a summary of staff-approved aging management programs (AMPs) for the aging of many SCs subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources used to review an applicant's LRA can be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the SCs used throughout the industry. The report also serves as a reference for both applicants and staff reviewers to quickly identify AMPs and activities that the staff determined can provide adequate aging management during periods of extended operation.

1.2.2 Environmental Review

Part 51 of 10 CFR governs environmental protection regulations. In December 1996, the staff revised the environmental protection regulations to facilitate the environmental review for license renewal. The staff prepared the GEIS to document its evaluation of the possible environmental impacts of renewed licenses for nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings applicable to all nuclear power plants. These generic findings are codified in Appendix B to Subpart A of 10 CFR Part 51. Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report must also include analyses of environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues).

In accordance with the National Environmental Policy Act of 1969 and the requirements of 10 CFR Part 51, the staff reviewed the plant-specific environmental impacts of license renewal, including whether the GEIS had not considered new and significant information. As part of its scoping process, the staff held a public meeting November 1, 2005, in Toms River, New Jersey, to identify environmental issues specific to the plant. The draft, plant-specific Supplement 28 to the GEIS, dated June 2006, documents the results of the environmental review and includes a preliminary recommendation on the license renewal action. The staff held another public meeting on July 12, 2006, in Toms River, New Jersey, to discuss draft GEIS Supplement 28. After considering comments on the draft, the staff published the final, plant-specific GEIS Supplement 28, on January 29, 2007.

1.3 Principal Review Matters

Part 54 of 10 CFR describes the requirements for renewing operating licenses for nuclear power plants. The staff performed its technical review of the LRA in accordance with NRC guidance and the requirements of 10 CFR Part 54. Section 54.29 of 10 CFR sets forth the standards for renewing a license. This SER describes the results of the staff's safety review.

Section 54.19(a) of 10 CFR requires license renewal applicants to submit general information. The applicant provided this general information in LRA Section 1. The staff reviewed LRA Section 1 and found that the applicant had submitted the information required by 10 CFR 54.19(a).

Section 54.19(b) of 10 CFR requires each LRA to include "conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." In the LRA, the applicant stated the following regarding this issue:

> The current indemnity agreement (No. B-37) for Oyster Creek states in Article VII that the agreement shall terminate at the time of expiration of the licenses specified in Item 3 of the Attachment to the agreement. Item 3 of the Attachment to the indemnity agreement lists license number, DPR-16. Applicant requests that any necessary conforming changes be made to Article VII and Item 3 of the Attachment, and any other sections of the indemnity agreement as appropriate to ensure that the indemnity agreement continues to apply during both the terms of the current license and the terms of the renewed license. Applicant understands that no changes may be necessary for this purpose if the current license number is retained.

The staff intends to maintain the original license number upon issuance of the renewed license, if approved. Therefore, conforming changes to the indemnity agreement need not be made and the requirements of 10 CFR 54.19(b) have been met.

Section 54.21 of 10 CFR requires each LRA to contain (a) an integrated plant assessment, (b) a description of any CLB changes that occurred during the staff's review of the LRA, (c) an evaluation of TLAAs, and (d) a UFSAR supplement. LRA Sections 3, 4, and Appendix B address the license renewal requirements of 10 CFR 54.21(a) and (c). LRA Appendix A as supplemented by AmerGen letters 2130-06-20354 and 2130-06-20258 contains the license renewal requirements of 10 CFR 54.21(d).

Section 54.21(b) of 10 CFR requires that each year, following submission of the LRA, and at least three months before the scheduled completion of the staff's review, the applicant must submit an amendment to the LRA that identifies any changes to the facility's CLB materially affecting the contents of the LRA, including the UFSAR supplement. The applicant submitted an update to the LRA, by letter dated July 18, 2006, which summarizes the changes to the CLB that have occurred during the staff's review of the LRA. In a subsequent letter on December 3, 2006, as corrected by letter dated December 15, 2006, the applicant submitted an update to the LRA to incorporate changes from the October 2006 refueling outage. These submissions satisfy the requirements of 10 CFR 54.21(b).

Section 54.22 of 10 CFR 54.22 requires the LRA to include changes or additions to the technical specifications necessary to manage the effects of aging during the period of extended operation. In LRA Appendix D, the applicant stated that it had not identified any technical specification changes necessary to support issuance of the renewed operating license for OCGS. This statement adequately addresses the requirement specified in 10 CFR 54.22.

The staff evaluated the technical information required by 10 CFR 54.21 and 10 CFR 54.22 in accordance with NRC regulations and the guidance provided by the SRP-LR. SER Sections 2, 3, and 4 document the staff's evaluation of the technical information in the LRA.

As required by 10 CFR 54.25, the ACRS will issue a report to document its evaluation of the staff's review of the LRA and associated SER. SER Section 5 will incorporate the ACRS report, once it is issued. SER Section 6 documents the findings required by 10 CFR 54.29.

The final, plant-specific GEIS Supplement 28 will document the staff's evaluation of the environmental information required by 10 CFR 54.23 and will specify the considerations related to renewing the license for OCGS. The staff will prepare this supplement separately from this SER.

1.4 Interim Staff Guidance

The license renewal program is a living program. The staff, industry, and other interested stakeholders gain experience and develop lessons learned with each renewed license. The lessons learned address the staff's performance goals of safety and security; openness in the regulatory process; effectiveness, efficiency, realistic, and timely action; and excellence in agency management. Interim staff guidance (ISG) is documented for use by the staff, industry, and other interested stakeholders until it is incorporated into such license renewal guidance documents as the SRP-LR and the GALL Report.

The following table provides the current ISG, issued by the staff, as well as the SER sections in which the staff addresses each ISG issue.

ISG Issue (Approved ISG No.)	Purpose	SER Section
Nickel-alloy components in the reactor pressure boundary **(LR-ISG-19B)**	Cracking of nickel-alloy components in the reactor pressure boundary. ISG under development. NEI and EPRI-MRP will develop an augmented inspection program for GALL AMP XI.M11-B. This AMP will not be completed until the NRC approves an augmented inspection program for nickel-alloy base metal components and welds as proposed by EPRI-MRP.	N/A (PWRs only)
Corrosion of drywell shell in Mark I containments **(LR-ISG-2006-01)**	To address concerns related to corrosion of drywell shell in Mark I containments.	3.0.3.2.27 3.0.3.2.23 3.5 4.7.2

1.5 Summary of Open Items

As a result of its review of the LRA, including additional information submitted to the staff through July 10, 2006, the staff identified the following open items (OIs), which remained open when the SER with open items was issued in August 2006. An issue is considered open if the applicant has not presented sufficient information or if the staff has not completed its review. Each OI has been assigned a unique identifying number. By letters dated April 7, June 20, December 3, and December 15, 2006, and February 15, 2007, the applicant responded to those OIs. The staff reviewed these responses and closed each of the OIs. The basis for closing the OIs is as follows:

OI 4.7.2-1.1: (Section 4.7.2 - Drywell Corrosion)

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide the following information: For the drywell corrosion during the late 1980s and the new corrosion found during the subsequent inspections, provide the process used to establish confidence that the sampling done to identify the areas of corrosion has been adequate.

In its response dated April 7, 2006, the applicant emphasized that it employs a robust process to establish confidence that the nature and locations of sampling done and areas considered for identifying the areas of corrosion have been adequate. The applicant stated that the elements of process had been developed over several years and defined in several technical documents submitted to the NRC in the 1990s. In addition, the applicant stated that OCGS has conducted extensive examinations to identify the cause of drywell corrosion, employed a robust sampling process, quantified with reasonable assurance the extent of drywell shell thinning due to corrosion, and assessed its impact on the drywell's structural integrity.

The staff's review of the applicant's response determined that there had been no UT measurements taken in the lower portion of the spherical area above the sand-pocket area. The staff requested that the applicant clarify its UT sampling plan for the entire drywell shell assessment.

In its supplemental response dated June 20, 2006, the applicant stated:

> A review of the drywell fabrication and installation details show that the welds that attach the 0.770 inches (the correct thickness is 0.770 inches, not 0.722 inch as indicated in the meeting notes) nominal plates to the 1.154 inch nominal plates at elevation 23 ft 6 7/8 inch are double bevel full penetration welds. The external edge of the 1.154 inches plates is tapered to 3 to 12 minimum as required by ASME Section VIII, Subsection UW-35, while the internal edge of the 1.154 inch plates are flush with the 0.770 inch plates. Thus there are no ledges that could retain water leakage and result in more severe corrosion than in areas included in the inspection program. Also, this joint is located below the equatorial center of the sphere. Therefore, in the event that water may run down the gap between the drywell shell and the concrete wall it would not collect on this joint.
>
> In 1991, Oyster Creek performed random inspections of the drywell shell. Ultrasonic testing inspections were conducted at 19 locations on either the 1.154 inch thick plates or on the 0.770 inch thick plates. The UT measurements were taken on a 6 inch x 6 inch grid (49 UTs) at each location. The UT measurement results show that thinning of the plates at these locations is less severe than the areas that are included in the corrosion-monitoring program. For this reason, the transition area was not added to the corrosion-monitoring program. Based on the above, AmerGen concludes that areas monitored under the drywell corrosion monitoring program bound the transition (from 1.154 inches to 0.770 inch thick plates) area of the drywell shell. Nevertheless, UT measurements will be taken on the 0.770 inch thick plate, just above the weld, prior to entering the period of extended operation.
>
> The measurements will be conducted at one location using the 6 inch x 6 inch grid. A second set of UT measurements will be taken two refueling outages later at the same location. The results of the measurements will be analyzed and evaluated to confirm that the rate of corrosion in the transition is bounded by the rate of corrosion of the monitored areas in the upper region of the drywell. If corrosion in the transition area is found to be greater than areas monitored in the upper region of the drywell, UT inspections in the transition area will be performed on the same frequency as those performed on the upper region of the drywell (every other refueling outage).
>
> Similarly, a review of fabrication and installation details of the containment drywell shell shows that the weld that connects the 2.625" knuckle plates to the 0.640"cylinder plates at elevation 71 ft 6 inch is a double bevel full penetration weld. The edges of the 2.625 inch plates were fabricated with a 3 to 12 taper to provide a smooth transition from the thicker to the thinner plate as required by ASME Section VIII, Subsection UE-35. Thus there are no ledges that could retain water leakage and result in more severe corrosion than the areas included in the inspection program.
>
> In 1991, Oyster Creek performed random inspections of the drywell shell. Ultrasonic testing (UT) inspections were conducted at 18 locations on the 2.625

inch thick knuckle plate and at four (4) locations on the 0.640 inch thick cylinder plate. The UT measurements were taken on a 6 inch x 6 inch grid (49 UTs) at each location. The UT measurement results showed that thinning of the plates at these locations was less severe than the areas that are included in the corrosion monitoring program. For this reason the knuckle area was not added to the corrosion monitoring program. Based on the above, AmerGen concludes that areas monitored under the drywell corrosion monitoring program bound the knuckle area of the drywell shell. However, UT measurements will be taken above the 2.625 inch knuckle plate in the 0.640 inch thick plate prior to entering the period of extended operation.

The staff believes that random sampling of UT measurement is valuable if the likelihood of corrosion is almost equal at every place in the region considered for UT measurements. If the geometry of the region and water flow in the air gap suggest that one area is more likely to have corrosion than another then the sampling plan must consider areas more likely to have corrosion in addition to the randomly selected areas. If the water flow in the air gap is high, the applicant's argument that the weld transition will not allow water accumulation would be accurate. However, if the water flow is slow, the applicant’s argument may not hold true. During the forthcoming outage, the applicant plans UT measurements at one location on each of the transition areas. The staff believes that measurement at four locations in each transition area would be more conservative. The locations along the thickness transition should be consistent with the areas that have large water accumulation and corrosion in the sand bed region. This item was identified as Open Item 4.7.2-1.1 in the SER with Open Items issued in August 2006.

The applicant updated the IWE Program Commitments in its December 3, 2006, submission (pages 73 and 74, items 10 and 11) with four separate sets of UT thickness measurements of the drywell shell at two areas of transition between shell plate thicknesses using a 6”x6” grid (*i.e.*, four separate 49-point UT sets at the transition at elevation 23’ 6 7/8” and four sets of UTs at elevation 71’-6”). The specific locations selected will be based on previous operational experience (*i.e.*, biased toward areas that have experienced corrosion or exposure to water leakage). These measurements will be at the same locations prior to the period of extended operation and at the second refueling outage after the initial inspection. If corrosion in these transition areas is greater than in areas monitored in the upper drywell, UT inspections in the transition areas will be on the same frequency as those in the upper drywell (every other refueling outage). Of these four locations, there were UT measurements at two for each transition area during 2006 outage. These first-time readings show that the mean and individual thicknesses meet acceptance criteria with adequate margin. There will be UT measurements in the remaining two locations at each transition area during the next outage prior to the period of extended operation.

The staff finds that the applicant’s actions to include in the program UT measurement of shell areas that may experience increased rates of corrosion resolves the staff concern. The basis for this finding is that the UT measurements should provide an adequate database to confirm whether the random sampling program for UT measurements is reasonably representative.

The staff, however, noted an inconsistency in the license renewal commitment list (pages 45 and 46, commitment number 27, “ASME Section XI, Subsection IWE,” item numbers 10 and 11) where it states that the UT measurements will be at one location. In a letter dated

December 15, 2006, the applicant noted the editorial error in its letter dated December 3, 2006. The applicant corrected the error by changing commitment 27 item numbers 10 and 11 from UT measurements at one location to UT measurements at four locations. Open Item OI 4.7.2-1.1 is closed.

In its letter dated February 15, 2007, the applicant revised a commitment (Commitment No. 27) by adding Item 21, which states that the performance of the full scope of drywell sand bed region inspections will be conducted every other refueling outage. The staff identified this commitment item as a license condition.

OI 4.7.2-1.2: (Section 4.7.2 - Drywell Corrosion)

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide the following information: For the drywell corrosion during the late 1980s and the new corrosion found during the subsequent inspections, provide the process used to establish confidence that the sampling done to identify the areas of corrosion has been adequate.

The staff's review of the April 7, 2006, response determined that the most susceptible bays in the sand pocket region of the drywell shell had been incorporated in the sampling. However, it was not clear to the staff whether the junction at elevation 6' 10.25" had been represented in the sampling. To determine whether the readings are taken at the vulnerable locations and reliable techniques are used, the staff requested that the applicant explain why this area should not be included in the sampling plan.

In its response dated June 20, 2006, the applicant noted that the drywell construction and fabrication details show that the presence of the drywell skirt prevents moisture intrusion into the plate. The applicant also noted that AmerGen has extensively investigated drywell corrosion, including the embedded shell. Plant-specific and industry operating experience indicate that corrosion of the embedded steel in concrete is not significant because the shell is protected by the high alkalinity of concrete. Corrosion could become significant only if the concrete environment is aggressive. The applicant also stated that historical data show that the environment in the sand bed region is not aggressive, and thus any water in contact with the embedded shell is not aggressive. The data show that corrosion of the drywell shell in the sand bed region is galvanic and impurities like chlorides and sulfates are not fundamentally involved in the anodic and cathodic corrosion reactions. Thus, only limited corrosion is anticipated for the drywell embedded shell.

The applicant concluded that corrosion monitoring of the sand bed region of the drywell shell is bounding with respect to corrosion that may have occurred on the drywell embedded shell before 1992. After 1992, corrosion of the embedded shell has not been significant because of the mitigative measures implemented and the robust drywell corrosion AMP.

The staff understands the applicant's technical basis to support the applicant's view that the inaccessible portion of the drywell shell (i.e., embedded between the concrete floor inside, and concrete outside) is not likely to be subject to the same type of severe corrosion as experienced in the sand bed area. However, the general corrosion in the liner plates embedded in concrete of a number of pressurized water reactor (PWR) and BWR containments suggests that certain irregularities during the construction (i.e. foreign objects or voids in the concrete) could trigger corrosion not arrested by the concrete environment. This suggestion is particularly significant for the plates potentially subject to water seepage. The applicant's position that the uniformly reduced thickness used in the GE analysis compensates for any corrosion that may have occurred before the area was sealed in 1992 has some validity. This item was Identified as Open Item OI 4.7.2-1.2 in the SER with Open Items issued in August 2006.

During the October 2006 refueling outage, the applicant inspected the embedded drywell shell in the trenches in bays #5 and 17 after removing the filler material in the trenches. The applicant observed approximately 5 inches of standing water in the trench in bay #5, and the trench in bay #17 was damp. Applicant investigations concluded that the likely water sources were a deteriorated drainpipe connection and a void in the bottom of the Sub-Pile Room drainage trough or condensation within the drywell that either fell or washed down the inside of the drywell shell to the concrete floor. Water samples from the trench in bay #5 were tested and determined to be non-aggressive in pH (8.4 – 10.21), chlorides (13.6 – 14.6 ppm), and sulfates (228 – 230 ppm).

The applicant entered the condition into the corrective action process. Several corrective actions included repair of the trough concrete in the area under the reactor vessel to prevent water from migrating through the concrete and reaching the drywell shell and caulking of the interface between the drywell shell and the drywell concrete floor/curb including the trench areas. The trench bay in bay #5 also was excavated to uncover an additional 6 inches of the internal drywell shell surface for inspection and UT thickness measurement. A total of 584 UT thickness measurements were taken with a 6”x6” template within the two trenches. Forty-two additional UT measurements were taken in the newly exposed area in bay #5.

Visual examination of the drywell shell within the two trenches detected minor surface rust with no recordable corrosion on the shell inner surface. The UT measurements indicated that the drywell shell in the trench areas had experienced a 0.038” reduction in average thickness since 1986. Amergen concluded that the wall thinning was a result of corrosion on the exterior surface of the drywell shell in the sand bed region between 1986 and 1992 when the sand was still in place and the corrosion was known.

An engineering evaluation to determine the impact of the as-found water on the continued integrity of the drywell concluded that the measured water chemistry values and the lack of any indications of rebar degradation or concrete surface spalling suggest that the protective passive film established during concrete installation at the embedded steel/concrete interface is still intact and that significant corrosion of the drywell shell is not expected as long as this benign environment is maintained. More specifically, this engineering evaluation indicates that no significant corrosion of the inner surface of the embedded drywell shell is anticipated for the following reasons:

- The water in contact with the drywell shell has been in contact with the adjacent concrete, which is alkaline, increases the pH of the water, and inhibits corrosion. This high-pH water contains levels of impurities significantly below the Electric Power Research Institute (EPRI) embedded steel guidelines action level recommendations.

- Any new water (*e.g.*, reactor coolant) entering the concrete-to-shell interface (now minimized by repairs) also increases pH by its migration through and contact with concrete, creating a non-aggressive, alkaline environment.

- Minimal corrosion of the wetted inner drywell steel surface in contact with concrete is expected only during outages because the drywell is inerted with nitrogen during operations. Even during outages, shell corrosion losses are expected to be insignificant as the exposure time to oxygen is very limited and the water pH is expected to be relatively high. Also repairs/modifications during the 2006 outage will further minimize exposure of the drywell shell to oxygen.

After the UT thickness measurements during the 2006 outage of the newly-exposed shell area in bay #5, which had not been examined since initial construction, a reduction of average shell thickness of 0.041" was observed. The applicant maintains that, although no continuing corrosion is expected, there is sufficient margin for both the 1.154" thick plate and the 0.676" thick plate even assuming the same reduction until the end of the period of extended operation.

The applicant also has enhanced the AMP to require periodic inspection of the drywell shell subject to concrete (with water) environments in the internal embedded shell area. After each inspection, UT thickness measurements will be evaluated and compared to previous UT thickness measurements. If results are unsatisfactory additional corrective actions, as necessary, will maintain drywell shell integrity throughout the period of extended operation.

To investigate the feasibility of state-of-the-art non-destructive examination techniques to determine the condition of the embedded region, the applicant contacted EPRI and other utility owners that use these techniques. After discussions and findings, the applicant understood that a "guided wave" technology may be able to provide some qualitative information on whether the embedded shell has undergone corrosion; however, neither this nor any other known non-destructive methods could determine the thickness of the embedded drywell shell or the specific extent of corrosion.

Based on review of the applicant's evaluation of the condition of the inaccessible portion of drywell shell embedded in concrete, the applicant's actions to date, and the enhanced inspection program including a detailed UT measurement plan to which the applicant committed, the staff concludes with reasonable assurance that the environment in the region is sufficiently non-aggressive for no significant progressive corrosion. Therefore, the staff concern is resolved and Open Item 4.7.2-1.2 is closed.

In its letter dated February 15, 2007, the applicant change a commitment (Commitment No. 27) by adding Item 20, which states AmerGen is committed to perform visual and UT inspections of the drywell shell in the inspection trenches in drywell bays #5 and #17. AmerGen will monitor the two trenches for the presence of water during each refueling outage. The staff identified this commitment item as a license condition.

OI 4.7.2-1.3: (Section 4.7.2 - Drywell Corrosion)

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide the following information: A summary of the factors considered in establishing the minimum required drywell thickness.

In its response dated April 7, 2006, the applicant explained that the factors considered in establishing the minimum required drywell thickness at various elevations of the drywell are described in detail in engineering analyses documented in two GE reports, Index Nos. 9-1, 9-2, and 9-3, 9-4.

In the applicant's discussion, a summary of the methods and assumptions used in the buckling analysis of the shell in the sand-pocket area has been given. Although the NRC has not approved ASME Code Case N-284 for use on a generic basis, the staff does not take exception to the use of average compressive stress across the metal thickness for buckling analysis of the as-built shell. However, if the corrosion has reduced the strength of the remaining metal through the cross section, this use may not be valid. The staff requested that the applicant address this issue.

In its response dated June 20, 2006, the applicant discussed its use of ASME Code Case N-284:

> Although Revision 1 of Code Case 284 had not yet been issued when the report (An ASME Section VIII Evaluation of Oyster Creek Drywell for Without Sand Case, Part II - Stability Analysis," GE Report, Index No. 9-4, Revision 0, DRF # 00664) was written, the authors consulted with the primary author of the revision. Based on those discussion, the plasticity correction factors used in the evaluation are the same as those in Figure 1610-1 of Code Case N-284 Revision 1.

The applicant stated that the technical approach used in the stability evaluation of Reference 2 is entirely consistent with the guidelines in ASME Code Case N-284, Revision 1. In addition, the applicant concluded that the corrosion on the outside surface of the shell will not introduce eccentricities that would significantly impact the “e/t” value of 1.0 assumed in ASME Code Case N-284. The applicant also stated that it expected additional eccentricity from shell corrosion in service to be accommodated within the allowable limit for imperfections.

The staff believed that the applicant provided a thorough explanation of the factors considered in applying the ASME Code Case N-284-1 for buckling analysis of the corroded shell in the sand bed area of the drywell shell. However, the applicant did not address whether it is appropriate to assume the same strength across the corroded section of the shell. The incorporation of the “e/t” corrosion concept with a representative distribution of strength along the corroded section that recognize the lower strength at the corroded side and full strength at the inside surface, could support the claim of conservatism in the analysis. This item was identified as Open Item OI 4.7.2-1.3 in the SER with Open Items issued in August 2006.

On further evaluation of the applicant's information, the staff concludes that the stability evaluation was consistent with the guidelines of ASME Code Case N-284-1. The staff's concern about use of the same section strength across the corroded section of the shell is addressed by Code Case N-284-1, which uses conservative assumptions to determine shell capacity reduction factors (*i.e.*, assumption of imperfection limit indicated by parameter “e/t” to be 1.0 in the code case) expected to compensate reasonably for such use of the same section strength. In addition, the applicant conservatively assumed the local corroded thickness for the entire drywell shell region and demonstrated that the code-allowable stresses were satisfied consistently with the guidelines of the code case. Thus, this analysis adds a margin of safety for the drywell stability evaluation. On this basis, the staff believes that the stability evaluation method is adequate and acceptable, and the staff’s concern is resolved. Open Item 4.7.2-1.3 is closed.

OI 4.7.2-1.4: (Section 4.7.2 - Drywell Corrosion)

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide the following information: A summary of the factors considered in establishing the minimum required drywell thickness.

In its response dated April 7, 2006, the applicant explained that the factors considered in establishing the minimum required drywell thickness at various elevations of the drywell are described in detail in engineering analyses documented in two GE reports, Index Nos. 9-1, 9-2, and 9-3, 9-4.

For the localized thin areas, the applicant uses the provision of NE-3213.10 of Subsection NE of ASME Code Section III. This provision, although not directly applicable to the randomly thin areas caused by corrosion, if used with care and adequate conservatism, could provide information about the primary stress levels at the junction of the thin and thick areas. The staff requested that the applicant provide a summary of the process used to address this issue.

In its response dated June 20, 2006, the applicant noted that "although provisions in ASME Code Section III, Subsection NE-3213.10 are not directly applicable to the randomly thin areas caused by corrosion, AmerGen believes that the provisions are applicable to the analysis of Oyster Creek drywell shell based on the following:

- The stress analysis of Oyster Creek drywell presented in Reference 1 satisfies the local primary stress requirements of NE-3213.10. Conservatism in the allowable primary stress intensity value, the assumed peak pressure during the LOCA condition and the assumption of local corroded thickness in the entire region of the drywell provide additional structural margin.

- The Code primary stress limits are satisfied in the corroded condition and the number of fatigue cycles is small, the surface discontinuities from corrosion do not represent a significant structural integrity concern.

- The applicant indicated that UT measurements of the drywell shell above the sand bed region had shown that the measured general thickness contains significant margin. The applicant stated that the ongoing corrosion in that region is insignificant and that the margin could be applied to offset uncertainties related to surface roughness.

- The applicant stated that UT measurements of the drywell shell in the sand bed region show that the measured general thickness is greater than the 0.736’” thickness assumed in the buckling analysis by significant margins except in two bays, 17 and 19. (Refer to response to RAI 4.7.2-1(d), Table-2). The margin in the general thickness of the two bays is 0.074” and 0.064” respectively. As significant additional corrosion is not expected in the sand bed region, the applicant applied the margin to offset uncertainties related to the surface roughness.

Because the staff had not completed its evaluation, this item was identified as Open Item OI 4.7.2-1.2 in the SER with Open Items issued in August 2006.

After further evaluation of the applicant’s justification, the staff accepts the use of the NE-3213.10 provisions of Subsection NE of ASME Code Section III. The staff acceptance is based on the applicant’s conservative approaches to its determination of the allowable shell capacity. Specifically, the applicant demonstrated acceptable shell capacity based on a conservative LOCA peak internal pressure *(i.e.*, peak internal pressure of 62 psi in the evaluation versus the 44 psi peak internal pressure in an Oyster Creek specific calculation approved by the NRC in 1993), use of a local corroded thickness for the entire region of the drywell, and compliance with local primary stress code limits in the corroded condition. In addition, the applicant expects its enhanced actions to prevent significant additional corrosion in the sand bed region. With this information, the staff’s concern is resolved and Open Item 4.7.2-1.4 is closed.

<u>OI 4.7.2-3:</u> (Section 4.7.2 - Drywell Corrosion)

In RAI 4.7.2-3 dated March 10, 2006, the staff noted that leakage from the refueling seal has been identified as one of the reasons for accumulation of water and contamination of the sand-pocket area. The refueling water passes through the gap between the shield concrete and the drywell shell in the long length of inaccessible areas. As there is a potential for corrosion, ASME Code Subsection IWE would require augmented inspection of this area. The staff requested that the applicant provide a summary of inspections (visual and NDE) and mitigating actions to prevent water leaks from the refueling seal components.

In its response dated April 7, 2006, the applicant stated that the refueling seals at OCGS consist of stainless steel bellows. In the mid-to-late 1980s, GPU conducted extensive visual and NDE inspections to determine the source of water intrusion into the seismic gap between the drywell concrete shield wall and the drywell shell and accumulation in the sand bed region. The inspections concluded that the refueling bellows (seals) were not the source of water leakage. The bellows were repeatedly tested by helium (external) and air (internal) with no indication of leakage. Furthermore, any minor leakage from the refueling bellows would be collected in a concrete trough below the bellows. The concrete trough is equipped with a drain line that would direct any leakage to the reactor building equipment drain tank and prevent it from entering the seismic gap. The drain line has been checked before refueling outages to confirm that it is not blocked. The only other seal is the gasket for the reactor cavity steel trough drain line. This gasket was replaced after the tests showed that it was leaking. However, the gasket leak was ruled out as the primary source of water observed in the sand bed drains because there is no clear leakage path to the seismic gap. Minor gasket leaks would be collected in the concrete trough below the gasket and would be removed by the drain line like leaks from the refueling bellows.

In addition, the applicant noted that additional visual and NDE (dye penetrant) inspections on the reactor cavity stainless steel liner had identified a significant number of cracks, some throughwall. Engineering analysis concluded that the cracks were most probably caused by mechanical impact or thermal fatigue, not intergranular stress corrosion cracking (IGSCC). These cracks were determined to be the source of refueling water that passed through the seismic gap. To prevent leakage through the cracks, GPU installed an adhesive-type stainless steel tape to bridge any observed large cracks and subsequently applied a strippable coating. This repair greatly reduced leakage and was implemented every refueling outage while the reactor cavity was flooded.

The applicant noted that OCGS has a long-time commitment to monitor the sand bed region drains for water leakage. A review of plant documentation provided no objective evidence that the commitment had been implemented since 1998. OCGS Issue Report No. 348545 was issued, in accordance with the corrective action process, to document the lapse in implementing the commitment and to reinforce strict compliance with commitment implementation in the future, including during the period of extended operation.

The applicant also committed (Commitment No. 27) to augmented inspections of the drywell in accordance with ASME Code Section XI, Subsection IWE. These inspections consist of UT examinations of the upper region of the drywell and visual examinations of the protective coating on the exterior of the drywell shell in the sand bed region. UT measurements will supplement the visual inspection of the coating measurements from inside the drywell once before entering the period of extended operation and every 10 years during the period of extended operation.

The staff's review of the applicant's response determined that the epoxy coating applied in the sand-bed region of the shell has a limited life and that water leakage from the air gap has not been prevented. With these observations, the staff requested that the applicant provide a systematic program of examination of the coating for confidence that the preventive measure is adequately implemented at all locations in the sand-pocket areas.

In its response dated June 20, 2006, the applicant committed to monitoring the sand bed region drains on a daily basis during refueling outages and take the following actions if water is detected. The following actions will be completed prior to exiting the outage:

- The source of water will be investigated and diverted, if possible, from entering the gap between the drywell shell and the drywell shield wall.

- The water will be chemically analyzed to aid in determining the source of leakage.

- A remote inspection will be performed in the trough drain area to determine if the trough drains are operating properly.

- The condition of the coating and the moisture barrier (seal) in the affected bays will be inspected.

- If the coating is degraded and visual inspection indicates corrosion is taking place, then UT thickness measurements will be taken in the affected areas of the sand bed region. The measurements will be taken from either inside or outside the drywell to ensure that the shell thickness in areas affected by water leakage is measured. UT thickness measurements and evaluation will be consistent with the existing program.

- The degraded coating and/or the seal will be repaired in accordance with station procedures.

- UT measurements will be taken in the upper region of the drywell consistent with the existing program.

The applicant also committed (Commitment No. 27) to monitor the sand bed region drains quarterly during the operating cycle. The applicant stated that, if water is detected, actions listed below will be taken. Actions that can only be completed during an outage will be completed during the next scheduled refueling outage.

- The leakage rate will be quantified to determine a representative flow rate. The leakage rate will be trended.

- The source of water will be investigated and diverted, if possible, from entering the gap between the drywell shell and the drywell shield wall.

- The water will be chemically analyzed to determine the source of leakage.

- The condition of the coating and the moisture barrier (seal) in the affected bays will be inspected during the next refueling outage or an outage of opportunity.

- If the coating is degraded and visual inspection indicates corrosion has taken place, then UT thickness measurements will be taken in the affected areas of the sand bed region from either inside or outside the drywell to ensure that the shell thickness in areas affected by water leakage is measured. UT thickness measurements and evaluation of the results will be consistent with the existing program.

- UT measurements will be taken in the upper region of the drywell consistent with the existing program.

- The degraded coating or the seal will be repaired in accordance with station procedures.

The staff believes that applicant had not provided sufficient information regarding the extent that coated surfaces will be examined during each inspection. This item was identified as Open Item OI 4.7.2-3 in the SER with Open Items issued in August 2006.

In a letter dated June 23, 2006, the applicant committed to monitoring of the coating on the drywell shell exterior in the sand bed region as part of its ASME Section XI, Subsection IWE Program and of its Protective Coating Monitoring and Maintenance Program. The applicant committed to additional visual inspections of the epoxy coating in all 10 drywell bays at least once prior to the period of extended operation. In a letter dated December 3, 2006, the applicant stated that 100 percent of the epoxy coating had been inspected during the October 2006 outage with no evidence of flaking, blistering, peeling, discoloration, or other signs of coating distress. The staff finds that these commitments with the IWE program and the absence of evidence of coating deterioration in the October 2006 inspection resolve the concern over the extent of coatings inspections. The staff’s concern is resolved and Open Item 4.7.2-3 is closed.

1.6 Summary of Confirmatory Items

The staff's review of the LRA, including additional information submitted to the staff through December 15, 2006, identified no confirmatory items (CIs). An issue was considered confirmatory if the staff and the applicant have reached a satisfactory resolution, but such information has not yet been submitted to the staff.

1.7 Summary of Proposed License Conditions

As a result of its review of the LRA, recommendations from the Advisory Committee on Reactor Safeguards, and subsequent information and clarifications from the applicant, the staff, at present, proposes seven license conditions.

The first license condition requires the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the next UFSAR update, as required by 10 CFR 50.71(e), following the issuance of the renewed license.

The second license condition requires future activities identified in the UFSAR supplement to be completed prior to entering and during the period of extended operation.

The third license condition requires all surveillance capsules placed in storage to be maintained for future insertion. Any changes to storage requirements must be approved by the staff as required by 10 CFR Part 50, Appendix H.

The fourth license condition requires the applicant to perform full scope inspections of the drywell sand bed region every other refueling outage.

The fifth license condition requires the applicant to monitor drywell trenches every refueling outage to identify and eliminate the sources of water and receive NRC approval prior to restoring the trenches to their original design configuration.

The sixth license condition requires the applicant to perform an engineering study prior to the period of extended operation to identify options to eliminate or reduce the leakage in the OCGS refueling cavity liner.

The seventh license condition requires the applicant to perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

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intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.23 ASME Section XI, Subsection IWE

Summary of Technical Information in the Application. In LRA Section B.1.27, the applicant described the existing ASME Section XI, Subsection IWE Program as consistent, with an exception, with GALL AMP XI.S1, "ASME Section XI, Subsection IWE."

The ASME Section XI, Subsection IWE Program provides for inspection of primary containment components and the containment vacuum breakers system piping and components. It is implemented through station plans and procedures and covers steel containment shells and their integral attachments; containment hatches and air locks, seals and gaskets, containment vacuum breakers system piping and components, and pressure retaining bolting. The program includes visual examination and limited surface or volumetric examination, when augmented examination is required, to detect loss of material. The program also manages loss of sealing for seals and gaskets and loss of preload for pressure-retaining bolting. Procurement controls and installation practices, defined in plant procedures, ensure that only approved lubricants and tension or torque are applied. The program complies with Subsection IWE for steel containments (Class MC) of ASME Section XI, 1992 Edition including 1992 Addenda, in accordance with the provisions of 10 CFR 50.55(a).

Staff Evaluation. During its audit and review, the staff reviewed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.23.

During the onsite audits of October 3-7, 2005, January 23-27, 2006, February 13-17, 2006, and April 19-20, 2006, the staff conducted an in-depth review of (1) the OCGS history of containment degradation due to corrosion, (2) the corrective actions taken at the time, (3) the current IWE augmented inspections and other programs and activities to monitor/mitigate additional corrosion, and (4) the applicant's license renewal commitments to manage aging of the degraded containment during the period of extended operation.

Through the audit process, the applicant made a number of significant new commitments to manage aging of the drywell shell. However, three issues remain unresolved. The staff's review of the applicant's original license renewal commitments, the development of the applicant's new commitments, and the remaining unresolved issues are documented in the Audit and Review Report. To summarize the staff's evaluation of the containment corrosion issue, the staff focused on the following four specific areas:

(1) water leakage from the refueling cavity into the annulus between the drywell and the shield wall

(2) corrosion of the upper drywell region above the former sand bed region

(3) corrosion of the former sand bed region of the drywell

(4) pitting corrosion of the suppression chamber (torus)

The operating experience and proposed aging management activities for each of these areas were reviewed in detail, and additional information was requested, as necessary, to facilitate a thorough assessment and evaluation of the applicant's aging management plans for the license renewal period. The results of this detailed audit are documented in the following paragraphs. In addition, the staff's evaluation of the information in each of these four areas is presented under the drywell degradation issue at the end of this section.

<u>Water Leakage from the Refueling Cavity</u>. During the audit, the applicant stated that a special coating is applied to the refueling cavity liner prior to flooding the reactor for refueling to prevent leakage into the annular space between the drywell shell and the concrete shield wall. As a result, the applicant believes that water intrusion into the refueling cavity has been eliminated as a source of further degradation on the exterior surface of the drywell shell.

Since the applicant used this special coating to minimize water intrusion into the annulus between the drywell and the concrete shield wall; the staff requested that the applicant identify whether it is committed to continue the use of this special coating as part of its refueling procedure through the period of extended operation. If not, the applicant was asked to identify what enhanced inspections will be conducted during the period of extended operation to monitor potential corrosion on the drywell exterior surface from the upper flange region to the sand bed region.

In its response, the applicant stated that the strippable coating has been effective in mitigating water intrusion into the annular space and in reducing the rate of corrosion. The applicant committed to applying the strippable coating to the reactor cavity liner prior to flooding for refueling during the period of extended operation. In its letter dated April 4, 2006, the applicant committed (Commitment No. 27) to the following:

> Consistent with current practice, a strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the refueling cavity is flooded. This commitment applies to refueling outages prior to and during the period of extended operation.

In reviewing PBD-AMP-B.1.27 for the applicant's ASME Section XI, Subsection IWE Program, the staff noted that, page 7 of this document states that, "Under the current term, Oyster Creek is committed to the 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." In its letter dated April 4, 2006, the applicant committed (Commitment No. 27) to the following: The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for water leakage periodically.

The staff requested that the applicant describe this commitment in more detail. In its response, the applicant stated that the commitment for monitoring the sand bed drains is in a staff SER transmitted by letter November 1, 1995. This SER requested a commitment to perform inspections "3 months after the discovery of any water leakage." Subsequent correspondence from General Public Utilities Nuclear Corporation (GPUN) clarified the commitment after discussions with the staff. The commitment made and accepted by the staff in a February 15, 1996, letter was to perform additional inspections of the drywell 3 months after discovery of any water leakage during power operation between scheduled drywell inspections. The requirement was not meant to apply to minor leakage from normal refueling activities. This commitment is consistent with the present commitment in PBD-AMP-B.1.27.

The applicant further stated in its response that, although there is no formal leakage monitoring in place, there has been no reported evidence of leakage from the former sand bed drains. Issue Report #348545 was submitted into the corrective action process when this lack of formal leakage monitoring was discovered. Corrective actions have been initiated to create recurring activities controlled by work management process and procedures for all future required inspections to meet the present commitment. Because there has been no reported leakage, there has been no need to investigate the source of leakage, take corrective actions, evaluate the impact of leakage, or perform additional drywell inspections.

The applicant further stated that numerous actions have been taken to alleviate the previous water leakage problem since discovery of the consequent drywell shell corrosion. Some of the significant actions consisted of inspections of the reactor cavity wall, remote visual inspection of the trough area below the reactor cavity bellows seal area, and subsequent repair of the trough area and clearing of its drain. Clearing of the trough drain and repair of the trough route any leakage away from the drywell shell. In addition, a strippable coating is applied to the reactor cavity walls before the reactor cavity is filled with water to minimize the likelihood of leakage into the trough area. These preventive actions have resulted in no evidence of leakage over the years at the former sand bed drains.

During the ACRS meeting on February 1, 2007, the applicant agreed to perform an engineering study to investigate cost-effective replacement or repair options to eliminate or reduce reactor cavity liner leakage. By letter dated February 15, 2007, the applicant, in Commitment Number 27, “ASME Section XI, Subsection IWE,” item 19, committed to complete the engineering study prior to the period of extended operations.

Corrosion of the Upper Drywell above the Former Sand Bed Region. In reviewing the license renewal information for the upper region of the drywell shell, the staff noted that the applicant referred to the LRA Section 4.7.2, “Drywell Corrosion,” TLAA evaluation for further discussion. In LRA Section 4.7.2, the applicant stated that the disposition of this TLAA is in accordance with 10 CFR 54.21(c)(1)(iii), and the ASME Section XI, Subsection IWE Program is credited to address the drywell corrosion TLAA. In LRA Section 4.7.2, under Analysis, the applicant stated that the ASME Section XI, Subsection IWE Program ensures that the reduction in vessel thickness will not adversely affect the ability of the drywell to perform its safety function. The ASME Section XI, Subsection IWE Program performs periodic UT inspections at critical locations, performs calculations to track corrosion rates, projects vessel thickness based on conservative corrosion rates, and demonstrates maintenance of the minimum required vessel thickness.

The applicant further stated in the LRA that inspections conducted since 1992 demonstrate that, as a result of corrective actions, the corrosion rates are very low or, in some cases, arrested. The drywell surfaces that were coated show no signs of deterioration. Drywell vessel wall thickness measurements indicate substantial margin to the minimum wall thickness, even when projected to the year 2029 with conservative estimates of corrosion rates. The applicant stated that continued assessment of the observed drywell vessel thickness ensures that timely action can be taken to correct degradation that could lead to loss of the intended function.

The staff reviewed the applicant’s discussion of aging management activities for the upper region of the drywell shell and determined that additional information was needed on the augmented scope of IWE. In its response, the applicant stated that OCGS had been committed to the drywell corrosion program in 1986 before implementation of IWE in September 9, 2001. The program elements, including periodic UT inspections at critical locations, calculations to track corrosion rates, vessel thickness projections based on conservative corrosion rates, and demonstrations of maintenance of minimum required vessel thickness, are now incorporated into IWE as an augmented inspection. The applicant provided procedures ER-AA-330, ER-AA-330-007, OC-6, and 2400-GMM-3900.52 for review.

The applicant further stated in its response that examination of the drywell interior surfaces in the former sand bed region is included as part of the ASME Code Section XI IWE inspections. The inspection of the exterior surfaces of the drywell in the sand bed region is included in the Protective Coating Monitoring and Maintenance Program.

The applicant also provided a tabulation of measured thicknesses for the monitored elevation of the upper region of the drywell shell along with calculation 1302-187-E310-0037, which summarizes trending results, projected remaining wall thickness at the end of the period of extended operation, and the CLB minimum required thickness.

The applicant further stated that UT inspections are performed every other refueling outage and that calculation 1302-187-E310-0037 provides the corrosion calculation and end-of-operating life thickness calculation.

In its letter dated April 4, 2006, the applicant committed (Commitment No. 27) to conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage at the same locations currently measured prior to and during the period of extended operation.

In reviewing PBD-AMP-B.1.27 for the applicant’s ASME Section XI, Subsection IWE Program, the staff noted that, in the discussion on pages 25 through 31 of drywell corrosion above the sand bed region, the applicant stated that,

> 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.

During the audit, the staff requested that the applicant describe the measures to prevent water intrusion into the gap between the drywell shell and the concrete to allow the upper portion of the drywell to meet ASME Code requirements. In addition, the applicant was further asked to clarify whether these measures to prevent water intrusion were credited for license renewal, and, if not, to clarify how ASME Code requirements will be met during the period of extended operation.

In its response, the applicant stated that the measures taken to prevent water intrusion into the gap between the drywell shell and the concrete to allow the upper portion of the drywell to maintain the ASME Code requirements are the following:

- Cleared the former sand bed region drains to improve the drainage path.
- Replaced reactor cavity steel trough drain gasket, which was found to be leaking.
- Applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal identified cracks in the stainless steel liner.
- Confirmed that the reactor cavity concrete trough drains are not clogged.
- Monitored former sand bed region drains and reactor cavity concrete trough drains for leakage during refueling outages and plant operation.

The applicant further stated that OCGS is committed to implement these measures during the period of extended operation.

Corrosion of the Former Sand Bed Region of the Drywell. In reviewing information for the sand bed region at the bottom of the drywell, the staff noted that, in the ASME Section XI, Subsection IWE Program discussion of operating experience, the applicant had stated that sand was removed and a protective coating was applied to the shell to mitigate further corrosion. The coating is monitored periodically under the Protective Coating Monitoring and Maintenance Program, which is discussed in SER Section 3.0.3.2.27. The staff reviewed the Protective Coating Monitoring and Maintenance Program and determined that the coating is included within its scope. The staff noted that the discussion of operating experience in the Protective Coating Monitoring and Maintenance Program is similar to the discussion of operating experience in ASME Section XI, Subsection IWE Program.

The staff reviewed the applicant's aging management activities for the former sand bed region of the drywell shell and determined that additional information was needed on aging management of this region. In its response, the applicant stated that monitoring and maintenance of the coating in the former sand bed region are included in the scope of the Protective Coating Monitoring and Maintenance Program. These activities are in accordance with specifications SP-1302-32-035 and SP-9000-06-003, which are included in the program.

The applicant further stated in its response that aging management of the sand bed region is not included in the augmented inspection required by ASME Code Section XI, Subsection IWE. As stated in ASME Code Section XI, Subsection IWE operating experience, corrective actions that include cleaning and coating of the sand bed region implemented in 1992 have arrested corrosion. The coated surfaces were inspected in 1994, 1996, 2000, and 2004, and the inspection showed no coating failure or signs of degradation. Thus, the region is not subject to augmented inspection in accordance with IWE-1240. The coating will be inspected every other refueling outage during the period of extended operation consistent with commitments for the current term.

As a result of discussions between the staff and the applicant on January 26, 2006, and April 20, 2006, the applicant supplemented its initial response to include the following:

- OCGS will also perform periodic UT inspections of the drywell shell thickness in the sand bed region, as discussed previously in this section.
- OCGS will also enhance the Protective Coating Monitoring and Maintenance Program to require inspection of the coating credited for corrosion (torus internal, vent system internal, sand bed region external) in accordance with ASME Section XI, Subsection IWE Program. Details are provided later in this section.

- On April 20, 2006, OCGS provided supplemental information on torus coating.

Details of the enhancement to the Protective Coating Monitoring and Maintenance Program and the staff's evaluation of this AMP are discussed in SER Section 3.0.3.2.27.

After the applicant's initial response, the applicant was asked for its technical basis for not also crediting its ASME Section XI, Subsection IWE Program for managing loss of material due to corrosion in the former sand bed region of the drywell.

The applicant stated that visual inspection of the containment drywell shell, conducted in accordance with ASME Code Section XI, Subsection IWE, is credited for aging management of accessible areas of the containment drywell shell. Typically this inspection is for internal surfaces of the drywell. The exterior surfaces of the drywell shell in the sand bed region for Mark I containment are considered inaccessible by ASME Code Section XI, Subsection IWE; thus, visual inspection was not possible for a typical Mark I containment before the sand was removed from the sand bed region in 1992. After removal of the sand, an epoxy coating was applied to the exterior surfaces of the drywell shell in the sand bed region. The region was made accessible during refueling outages for periodic inspection of the coating. Subsequently, OCGS periodically visually inspected the coating under a CLB commitment implemented prior to the ASME Section XI, Subsection IWE Program. As a result, inspection of the coating was in accordance with the Protective Coating Monitoring and Maintenance Program. The applicant's evaluation of this AMP concluded the program is adequate to manage aging of the drywell shell in the sand bed region during the period of extended operation consistent with the CLB commitment and that inclusion of the coating inspection under the ASME IWE inspection is not required. However, the applicant will amend this position to commit to monitor the protective coating on the exterior surfaces of the drywell in the sand bed region in accordance with the requirements of ASME Code Section XI, Subsection IWE during the period of extended operation.

In its letter dated April 4, 2006, the applicant committed (Commitment No. 27) to the following: Prior to the period of extended operation, the applicant will perform additional visual inspections of the epoxy coating applied to the exterior surface of the drywell shell in the sand bed region so the coated surfaces in all 10 drywell bays will have been inspected at least once. In addition, the ISI program will be enhanced to require inspection of 100 percent of the epoxy coating every 10 years during the period of extended operation. These inspections will be in accordance with ASME Code Section XI, Subsection IWE. The inspections will be staggered so that at least three bays will be examined every other refueling outage.

In its letter dated April 4, 2006, the applicant committed (Commitment No. 27) to the following: UT thickness measurements of the drywell shell in the sand bed region will be every 10 years. The initial inspection will occur prior to the period of extended operation. The UT measurements will be taken from the inside of the drywell at the same locations of UT measurements in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT measurements will result in corrective actions: (1) additional UT measurements to confirm the readings, (2) notice to the staff within 48 hours of confirmation of the condition, (3) visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected, (4) an engineering evaluation of the extent of condition to determine whether additional inspections are required to assure drywell integrity, and (5) an operability determination and justification for operation until the next inspection. These actions will be completed prior to restart from the outage.

In its letter dated May 1, 2006, the applicant committed (Commitment No. 27) to the following: During the next UT inspections of the drywell sand bed region (reference AmerGen April 4, 2006, letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will use the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable.

The staff requested that the applicant provide a discussion of the scope of the current coating inspection program and the license renewal commitment. In its response the applicant stated that protective coatings on the exterior surfaces of the drywell shell in the sand bed region are monitored in accordance with the Protective Coating Monitoring and Maintenance Program. The current program requires visual inspection of the coating in accordance with Engineering Specification IS-328227-004. Inspection criteria are not provided by the specification. However, inspections are by individuals qualified for coating inspections. Acceptance criteria in the specification are that any coating defects be submitted for engineering evaluation. The inspection frequency is every other refueling outage.

The applicant further stated in its response that, as discussed with the staff, the existing Protective Coating Monitoring and Maintenance Program does not invoke all of the requirements of ASME Code Section XI, Subsection IWE. The applicant has committed (Commitment No. 27) to enhance the program to incorporate coated surfaces inspection requirements specified in ASME Code Section XI, Subsection IWE and has provided specific enhancements that will be made to the program as follow:

> Sand bed region external coating inspections will be per Examination Category E-C (augmented examination) and will require VT-1 visual examinations per IWE-3412.1.
>
> a. The inspected area shall be examined (as a minimum) for evidence of flaking, blistering, peeling, discoloration, and other signs of distress.
>
> b. Areas that are suspect shall be dispositioned by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.
>
> c. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of engineering evaluation.

During the audit, the staff asked the applicant for information related to inspections of the drywell sand bed region. In response, the applicant stated that the minimum recorded thickness in the sand bed region from approximately 120 UT measurements taken on the outside of the drywell shell is 0.618". The minimum recorded thickness in the sand bed region from the 6" by 6" UT measurement grids inside the drywell shell is 0.603". These minimum recorded thicknesses are isolated local measurements and represent single point UT measurements.

On April 19, 2006, the applicant supplemented its response, stating that the lowest recorded reading was 0.603 in December 1992. The applicant stated that a review of the previous readings for the period 1990 through 1992 and two subsequent readings taken in September 1994 and in 1996 shows that this point should not be considered valid. The average reading for this point taken in 1994 and 1996 was 0.888 inches. Point 14 in location 17D was the next lowest value of 0.646 inches recorded during the 1994 outage. A review of readings at this same point, taken during the period from 1990 through 1992, and subsequent readings taken in

1996 are consistent with this value. Thus, the minimum recorded thickness in the sand bed region from inside inspections is 0.646 inches instead of 0.603 inches.

The applicant further stated in its response that the 0.806 inches thickness provided to the staff verbally is an average minimum general thickness calculated based on 49 UT measurements taken in an area approximately 6 inches x 6 inches. Thus, the two local isolated minimum recorded thicknesses cannot be compared directly to the general thickness of 0.806 inches. The 0.806 inches minimum average thickness verbally discussed with the staff during the AMP audit was recorded in location 19A in 1994. Lower minimum average thickness values were recorded at the same location in 1991 (0.803 inches) and in 1992 (0.800 inches). However, the three values are within the tolerance of +/- 0.010 inches discussed with the staff.

The applicant further stated in its response that the minimum projected thickness depends on whether the trended data is before or after 1992, as demonstrated by corrosion trends. For license renewal the use of corrosion rate trends after 1992 is appropriate because of such corrosion mitigating measures as removal of the sand and coating of the shell. Then, using corrosion rate trends based on 1992, 1994, and 1996 UT data and the minimum average thickness measured in 1992 (0.800 inches), the minimum projected average thickness through 2009 and beyond remains approximately 0.800 inches. The projected minimum thickness during and through the period of extended operation will be reevaluated after UT inspections conducted prior to the period of extended operation and after UT inspections every 10 years thereafter.

The applicant further stated in its response that the engineering analysis that demonstrated compliance with ASME Code requirements had two parts, stress and stability analysis with sand and stress and stability analyses without sand. The analyses are documented in GE Reports Index No. 9-1, 9-2, 9-3, and 9-4 transmitted to the staff in December 1990 and in 1991, respectively. Index Nos. 9-3 and 9-4 were revised later to correct errors identified during an internal audit and resubmitted to the staff in January 1992.

The staff requested that the applicant provide information related to the evaluation of the results of the next UT inspection of the sand bed region. In its response, the applicant stated that the new set of UT measurements for the former sand bed region will be analyzed by the same methodology used to analyze the 1992, 1994, and 1996 UT data. The results will then be compared to the 1992, 1994, and 1996 UT results to confirm the previous no corrosion trend. Because of surface roughness of the exterior of the drywell shell, experience shows that UT measurements can vary significantly unless the UT instrument is positioned on the exact point as for the previous measurements. Thus, acceptance criteria will be based on the standard deviation of the previous data (+/-11 mils) and instrument accuracy of (+/-10 mils) for a total of 21 mils. Deviation from this value will be considered unexpected and requiring corrective actions described previously.

The staff's review of this information is in its evaluation of the drywell degradation issue presented at the end of this section.

<u>Pitting Corrosion of the Suppression Chamber (Torus)</u>. In reviewing information in the ASME Section XI, Subsection IWE Program discussion of operating experience for the suppression chamber (torus) and vent system, the staff noted that the applicant had stated that the coating is inspected every outage and repaired, as required, to protect the torus shell and the vent system from corrosion. The staff referred to the Protective Coating Monitoring and Maintenance Program for additional details. The staff reviewed the Protective Coating Monitoring and Maintenance Program and noted that, under operating experience, the applicant stated that torus and vent

header vapor space Service Level I coating inspections in 2002 found the coating in these areas in good condition. Inspection of the immersed coating in the torus found blistering that primarily in the shell invert but also on the upper shell near the water line. The majority of the blisters remained intact and continued to protect the base metal. However, several areas included pitting damage where the blisters were fractured. A qualitative assessment of the pits concluded that the pit depths were significantly less than the established acceptance criteria. The fractured blisters were repaired to reestablish the protective coating barrier.

To clarify, the staff asked the applicant for information pertaining to operating experience and license renewal aging management for the suppression chamber (torus) and vent system. In its response, the applicant stated that inspection of the suppression chamber (torus) and vent system coating is by divers every other outage in accordance with Engineering Specification SP-1302-52-120, which provides inspection and acceptance criteria for the coating and for pitting as a contingency in the event failure of the coating results in pitting. The coating is monitored for cracks, sags, runs, flaking, blisters, bubbles, and other defects described in the Protective Coating Monitoring and Maintenance Program.

The applicant further stated that the specification requires inspection of the torus and vent system surfaces for coating integrity. If pitting is observed isolated pits of 0.125 inches in diameter have an allowed maximum depth of 0.261 inches anywhere in the shell provided the center-to-center distance between the subject pits and neighboring isolated pits or areas of pitting corrosion is greater than 20 inches. Multiple pits that can be encompassed by a 2.5-inch diameter circle are limited to a maximum depth of 0.141 inches provided the center-to-center distance between the subject pitted area and neighboring isolated pits or areas of pitting corrosion is greater than 20 inches.

Plant documentation that describes the blistering and pitting and qualitative assessment performed, the established acceptance criteria, and corrective actions taken is included in PBD-AMP-B.1.27.

On April 19, 2006, the applicant supplemented its response to include the statement “Pits greater that 0.040 inches in depth shall be documented and submitted to engineering for evaluation.”

The applicant further stated in its response that the torus and vent system coating is classified Service Level I coating as described in the Protective Coating Monitoring and Maintenance Program. The program was evaluated against the 10 elements of GALL AMP XI.S8, “Protective Coating Monitoring and Maintenance Program” and found consistent without enhancements or exceptions. Acceptance criteria are evaluated in element 3.6 of the Protective Coating Monitoring and Maintenance Program (PBD-AMP-B.1.33). The inspection is performed by ASME Section XI Level II and Level III inspectors. Acceptance criteria for pits are based on engineering analysis that uses the method of ASME Code Case N-597 as guidance for calculation of pit depths that will not violate the local stress requirements of either ASME Code Section III, 1977 Edition or Section VIII, 1962 Edition.

The applicant also stated in its response that the inspection that discovered the blistering was conducted under the protective coating monitoring and maintenance program. Examinations are performed by ASME Section XI Level II and Level III inspectors. The applicant further stated in its response that both the ASME Section XI, Subsection IWE and the Protective Coating Monitoring and Maintenance Programs are credited to manage loss of material due to corrosion for the suppression chamber (torus) and the vent system for the period of extended operation.

On April 19, 2006, the applicant supplemented its response to clarify that during the period of extended operation, torus coating inspection will be performed in all 20 torus bays at a frequency of every other refueling outage for the current coating system. Should the coating system be replaced, the inspection frequency and scope will be re-evaluated. The inspection scope will, as a minimum, meet the requirements of ASME Code Subsection IWE. This specific commitment (Commitment No. 33) is associated with the Protective Coating Monitoring and Maintenance Program.

In its letter dated May 1, 2006, the applicant committed (Commitment No. 27) to the following: As noted in the applicant's April 4, 2006 letter to NRC, OCGS will perform torus coating inspections in accordance with ASME Code Section XI, Subsection IWE every other refueling outage prior to and during the period of extended operation. This new commitment clarifies that the scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will be re-evaluated. Inspection scope will, as a minimum, meet the requirements of ASME Code Section XI, Subsection IWE.

On April 19, 2006, the applicant supplemented its response, stating that Condition Report No. 373695 assignments 2 and 3 have been initiated to drive program improvements for the monitoring and trending of torus design margins, and to develop refined acceptance criteria and thresholds for entering coating defects and unacceptable pit depths into the corrective action process for further evaluation. These improvements will be incorporated into the inspection implementing documents prior to the next performance of these inspections, which is also prior to the period of extended operation. These improvements will be described in a letter to the NRC.

In its letter dated May 1, 2006, the applicant stated that it will develop refined acceptance criteria and thresholds for entering torus coating defects and unacceptable pit depths into the corrective action process for further evaluation. These improvements will be incorporated into the inspection implementing documents prior to the next performance of these inspections, which is also prior to the period of extended operation.

The staff finds this acceptable since it will provide additional criteria to determine whether degradation of the suppression chamber is being adequately managed.

On April 19, 2006, the applicant supplemented its response, stating that the answers provided previously on torus wall thickness were written to address specific concerns of the AMP audit team and were centered around worse case torus thickness margins existing on the torus shell due to corrosion. This supplemental information is being provided to reinforce that, based on all available inspection results, the average thickness of the torus remains at 0.385 inches. Based on the results of the inspections performed through 1993 (14R), it was concluded that the torus shell thickness had remained virtually unchanged following the repair and recoating efforts performed in 1984. This was communicated to the NRC via letter C321-94-2186 dated November 3, 1994, Amendment No. 177 to DPR-16 and SER dated February 21, 1995 for the electromatic relief valve (EMRV) technical specification change. Coating inspections performed subsequent to 1993 (14R) continue to confirm that the torus shell thickness has remained virtually unchanged following the repair and recoating efforts performed in 1984, and that the average thickness of the torus remains at 0.385 inches. Torus integrity will continue to be evaluated during future inspections (performed every other refueling outage) into the period of extended operation.

The applicant also clarified the extent of pitting corrosion. Pitting corrosion less than or equal to 0.040 inches was not repaired during the 1984 torus repair and recoating effort based on available margins and was found to be acceptable without any size restriction since it satisfied minimum uniform thickness requirements. Inspection activities subsequent to 1984 have identified 5 isolated pits that exceed 0.040 inches. The following areas have been mapped for trending and analysis during future inspections: 1 pit of 0.042 inches in bay 1; 1 pit of 0.0685 inches in bay 2; 2 pits of 0.050 inches in bay 6; 1 pit of 0.058 inches in bay 10. Shell thicknesses have been evaluated against code requirements and found to satisfy all design and licensing basis requirements. Therefore, the integrity of the torus shell has been verified to have adequate shell thickness margins to ensure design and licensing basis requirements can be maintained.

The applicant also supplemented its response to include the statement, “Pits greater that 0.040 inches in depth shall be documented and submitted to engineering for evaluation.”

The staff reviewed the applicant’s response and determined that it was responsive to the questions asked.

In reviewing PBD-AMP-B.1.27 for the applicant’s ASME Section XI, Subsection IWE Program, the staff noted that, in the discussion of torus degradation pages 25 to 31 of this document state that,

> Inspections 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 ASME Section XI, Subsection IWE 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 continue 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 maximum) 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 staff asked the applicant to confirm or clarify that (1) only the fractured blisters found in this inspection were repaired, (2) pits were identified where the blisters were fractured, (3) pit depths were measured and found to 50 mils maximum, (4) the inspection Specification SP-1302-52-120 includes pit-depth acceptance criteria for rapid evaluation of observed pitting, and (5) the minimum pit depth of concern is 141 mils (0.141 inches) and pits as deep as 261 mils (0.261 inches) may be acceptable.

In its response, the applicant stated that Specification SP-1302-52-120, “Specification for Inspection and Localized Repair of the Torus and Vent System Coating,” specifies repair requirements for coating defects exposing substrate and fractured blisters showing signs of corrosion. The repairs to which the inspection report referred included fractured blisters as well as any mechanically damaged areas which have exposed bare metal showing signs of corrosion. Therefore, only fractured blisters will be candidates for repair, not blisters that remain intact. The number and location of repairs are tabulated in the final inspection report prepared by Underwater Construction Corporation.

The applicant further stated in its response that coating deficiencies in the immersion region included blistering with minor mechanical damage. Blistering occurred primarily in the shell invert but was also noted on the upper shell near the water line. Most blisters were intact. Intact blisters were examined by removing the blister cap exposing the substrate. Corrosion attack under non-fractured blisters was minimal and generally limited to surface discoloration. Examination of the substrate revealed slight discoloration and pitting with pit depths less than 0.001 inches. Several blistered areas included pitting corrosion where the blisters were fractured. The substrate beneath fractured blisters generally exhibited a slightly heavier magnetite oxide layer and minor pitting (less than 0.010 inches) of the substrate.

In addition to blistering, random deficiencies that exposed base metal were identified in the torus immersion region coating (e.g., minor mechanical damage) during the 19R (2002) torus coating inspections. They ranged in size from 1/16 to ½ inches in diameter. Pitting in these areas was qualitatively evaluated and ranged from less than 10 mils to slightly more than 40 mils in a few isolated cases. Three quantitative pit depth measurements were taken in several locations in the immersion area of Bay 1. Pit depths at these sites ranged from 0.008 to 0.042 inches and were judged to be representative of typical conditions found on the shell. Prior to the 2002 inspection, 4 pits greater than 0.040 inches were identified. The pit depths were 0.058 inches (1 pit in 1988), 0.05 inches (2 pits in 1991), and 0.0685 inches (1 pit in 1992). The pits were evaluated against the local pit depth acceptance criteria and found acceptable.

The applicant also stated that the acceptance criteria for pit depth are as follow: Isolated pits of 0.125 inches in diameter have an allowed maximum depth of 0.261 inches anywhere in the shell provided the center-to-center distance between the subject pit and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This criterion includes old pits or old areas of pitting corrosion that have been filled or re-coated. Multiple pits that can be encompassed by a 2-1/2 inches diameter circle shall be limited to a maximum pit depth of 0.141 inches provided the center-to-center distance between the subject pitted area and neighboring isolated pits or areas of pitting corrosion is greater than 20.0 inches. This criterion includes old pits or old areas of pitting corrosion that have been filled or re-coated.

<u>Drywell Degradation Issue</u>. The staff evaluated the applicant's revised aging management commitments to address four distinct issues: (1) monitoring/eliminating water leakage, (2) corrosion in the upper drywell region, (3) corrosion in the former sand bed region, and (4) pitting corrosion in the suppression chamber (torus). The staff's evaluation of each area is discussed in the following paragraphs.

(1) <u>Monitoring/Eliminating Water Leakage in the Gap Between the Drywell and Shield Wall</u>. The applicant made a commitment (Commitment No. 27), to continue the use of the strippable coating for each refueling during the license renewal period. According to the applicant, this coating has been effective in eliminating water intrusion into the annular space between the drywell shell and the concrete shield wall. In the LRA, the applicant had not committed to continue its use.

The applicant also committed (Commitment No. 27) to investigate the source of leakage, take corrective actions, evaluate the impact of the leakage and, if necessary, perform additional drywell inspections in the event water leakage from the former sand bed region is found during the period of extended operation. Under the current license term, OCGS is committed to monitor the former sand bed region drains for water leakage. This commitment was not previously identified in the LRA.

The staff noted that while these new commitments address both mitigation of and monitoring for water leakage; they are an essential element of the applicant's overall program to manage aging of the degraded drywell during the license renewal period, the applicant has not established a leakage monitoring program.

However, the applicant indicated that there is no formal procedure in place to monitor leakage from the sand bed drains and stated, "Issue Report #348545 was submitted into the corrective action process when this was discovered. Corrective actions have been initiated to create recurring activities controlled with the work management process and procedures, to perform all future required inspections to meet the present commitment."

The staff found that the absence of a leakage monitoring program to meet the current license term commitment raises a question about the basis for the applicant's claim that water is no longer leaking into the annular gap between the drywell shell and the concrete shield wall. Subsequent to the audit, in response to RAI 4.7.2-1, by letter dated June 20, 2006, the applicant provided additional information regarding the AMP and activities associated with drywell leakage monitoring program. The staff's evaluation of the applicant's additional information and commitments is documented in SER Section 4.7.2.

(2) Upper Drywell Region. The applicant made a new license renewal commitment (Commitment No. 27), to continue UT measurements of the upper drywell region for the period of extended operation.

The applicant manages loss of material due to corrosion in the upper drywell region (spherical and cylindrical sections) by augmented examinations in accordance with IWE-1240. An UT survey is performed every other refueling outage (4 years) to detect any additional 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 to the end of plant life. The areas subject to periodic UT measurements were selected based on extensive exploratory testing to establish the most severely corroded locations in the drywell above the sand bed region. Corrosion of the upper drywell region is a TLAA per 10 CFR 54.21(c). The applicant's TLAA is documented in LRA Section 4.7.2. The applicant implements TLAA option (iii) and uses the UT inspection results from its IWE program to monitor remaining thickness, to periodically update the corrosion rate, and to periodically update the projected remaining thickness at the end of the license renewal period.

The evaluation of this TLAA is addressed in SER Section 4.

(3) Former Sand Bed Region of Drywell. In the LRA, the applicant's position was that corrosion in the former sand bed region has been completely arrested by the remedial actions already taken. The original LRA commitment was to inspect a section of coating every other outage (4 years) to confirm its soundness. The last UT readings were in 1996. As a result of the audit, the applicant made several new commitments to manage aging of the former sand bed region of the drywell during the period of extended operation. In its letters dated April 4, 2006, and May 1, 2006, the applicant revised the commitments:

- Monitor the protective coating on the exterior surfaces of the drywell in the sand bed region in accordance with the requirements of ASME Code Section XI, Subsection IWE during the period of extended operation (Commitment No. 27),
- Conduct periodic UT inspection of the former sand bed region before the license renewal period and every 10 years thereafter (Commitment No. 27),
- Attempt during the UT inspections of the sand bed region prior to the period of extended operation a UT inspection from the exterior of the drywell of some of the locally thinned areas identified in the 1992 inspection (Commitment No. 27),
- Inspect the remaining 50 percent of the external coating in the former sand bed region before the license renewal period (to date, only 50 percent of this coating has been inspected since it was applied in the early 1990s) and conduct a 100 percent re-inspection of the coating every 10 years during the license renewal period (Commitment No. 27),
- If additional corrosion of the sand bed region is identified by the UT inspection to be conducted before entering the license renewal period, initiate corrective actions that include one or all of the following, depending on the extent of identified corrosion:

    - Perform additional UT measurements to confirm the readings.
    - Notify the staff within 48 hours of confirmation of the identified condition.
    - Inspect the coatings in the sand bed region in areas where the additional corrosion was detected.
    - Perform an engineering evaluation to assess the extent of the condition and to determine whether additional inspections are required to assure drywell integrity.
    - Perform an operability determination and justification for continued operation until next scheduled inspection.

    These actions will be completed before restarting from an outage (Commitment No. 27).

The staff noted these new commitments for managing aging of the former sand bed region, but also noted the very small remaining margin between the minimum reported uniform thickness and the minimum required uniform thickness (0.800 inches vs. 0.736 inches). This apparent lack of margin led the staff to request additional information about (1) the UT inspection results and data reduction methods employed to determine the minimum remaining thickness and (2) the analytical methodology employed to determine the minimum required thickness for localized areas where the measured thickness is less than the minimum required uniform thickness. The applicant provided additional information on these subjects. During a followup onsite audit conducted April 19-20, 2006, the staff discussed these responses with the applicant in detail to ensure a complete understanding.

The staff reviewed the detailed UT thickness readings in the sand bed region taken from the inside surface through 1996 and on the outside surface in 1992. The staff pointed out a definite bias in the 1996 readings because the average thickness (based on 49 readings/location) increased at almost all locations. The staff and the applicant's personnel discussed possible causes for this bias, but no conclusions could be drawn.

The staff's review of the UT data confirmed that the remaining thickness in the former sand bed region significantly exceeds the minimum required thickness of 0.736 inches at most monitored locations. Several locations are close to the original design thickness of 1.154 inches. However, in a few very localized areas, primarily in Bays 1 and 13, remaining thicknesses less than 0.736 inches have been measured.

The staff also reviewed the technical basis documents that established compliance with ASME Code requirements. In response to a question, the applicant stated that the engineering analysis demonstrating compliance with ASME Code requirements was performed in two parts, stress and stability analysis with and without sand. The analyses are documented in GE Reports Index No. 9-1, 9-2, 9-3, and 9-4 transmitted to the NRC in December 1990 and in 1991, respectively. Index Nos. 9-3 and 9-4 were revised later to correct errors identified during an internal audit, and were resubmitted to the staff in January 1992.

The applicant stated that the drywell shell thickness in the sand bed region is based on stability analysis without sand (GE Report 9-4). The analysis is based on a 36-degree section model that takes advantage of symmetry of the drywell with 10 vents. The model includes the drywell shell from the base of the sand bed region to the top of elliptical head and the vent and vent header. The torus is not included in this model because the bellows provide a very flexible connection which does not allow significant structural interaction between the drywell and the torus. The analysis conservatively assumed that the shell thickness in the entire sand bed region had been reduced uniformly to a thickness of 0.736 inches.

The applicant further indicated that GE Letter Report "Sand Bed Local Thinning and Raising the Fixity Height Analysis" presents results demonstrating that assuming a uniform reduction in thickness of 27 percent to 0.536 inches over a 1 ft^2 area will create only a 9.5 percent reduction in the load factor and theoretical buckling stress for the whole drywell. A second buckling analysis assuming a wall thickness reduction of 13.5 percent to 0.636 inches over a 1 ft^2 area reduced the load factor and theoretical buckling stress by only 3.5 percent for the whole drywell.

The applicant further stated that to bring these results into perspective, a review of the NDE reports indicates there are 20 UT measured areas in the whole sand bed region with thicknesses less than 0.736 inches covering a conservative total area of 0.68 ft^2 of the drywell surface with an average thickness of 0.703 inches or 4.5 percent reduction in wall thickness. Furthermore, all of these very local wall areas are centered about the vents, significantly stiffening the shell. This stiffening effect limits the shell buckling in the shell sand bed region to the midpoint between two vents.

The staff reviewed the detailed UT thickness readings, the GE stability analyses, and the conservative assumptions used in the GE Letter Report, "Sand Bed Local Thinning and Raising the Fixity Height Analysis." The staff concludes that the degraded condition of the former sand bed region of the drywell shell measured in 1996 was adequate for its intended function in accordance with its design basis.

However, because there has been no UT inspection conducted since 1996 and the remaining corrosion margin in 1996 was less than 0.1 inches at several locations, the staff initiated further evaluation of the applicant's aging management commitment for UT inspection of the former sand bed region.

The applicant credited its Protective Coating Monitoring and Maintenance Program to monitor/maintain the protective coating on the exterior surface of the drywell in the former sand bed region. The staff evaluated this program in SER Section 3.0.3.2.27. The staff finds the enhancement to the protective coating monitoring and maintenance program acceptable because it ensures that the requirements of ASME Code IWE related to coating inspection will be implemented during the period of extended operation. The applicant's revised aging management commitment (Commitment No. 27) is to complete a 100 percent inspection of the coating (initiated in 1994 and currently 50 percent complete) prior to the license renewal period and to conduct subsequent 100 percent reinspections every 10 years during the license renewal period.

Because of the minimal corrosion margin remaining in the former sand bed region and the applicant's reliance on the coating to mitigate additional corrosion the staff initiated further review of the applicant's inspection program to ensure that the coating will continue to perform its intended function for the extended period of operation.

Subsequent to the audit, in response to RAI 4.7.2-1, by letter dated June 20, 2006, the applicant provided additional information regarding the AMP and activities associated with drywell shell corrosion. The staff's evaluation of the applicant's additional information and its commitments is documented in SER Section 4.7.2.

(4) Suppression Chamber (Torus). The applicant credited its Protective Coating Monitoring and Maintenance Program to monitor/maintain the protective coatings inside the suppression chamber (torus) to mitigate corrosion. The staff's detailed evaluation of the applicant's Protective Coating Monitoring and Maintenance Program is addressed in SER Section 3.0.3.2.27.

The staff questioned the applicability and implementation of ASME Code Case N-597-1 for developing pit depth acceptance criteria for the torus. Based on the acceptance criteria developed by the applicant, an isolated pit of 0.125 inches diameter on the inner surface is considered acceptable if its depth does not exceed 0.261 inches. According to the applicant, the torus as-built wall thickness is 0.385 inches. Therefore, a pit depth equal to 67 percent of the as-built thickness is considered acceptable if isolated. For a cluster of pits within a 2.5 inches diameter circle the acceptable pit depth is 0.141 inches or 37 percent of the as-built thickness. The acceptable pit depth includes allowance for an assumed 0.0009 inches per year corrosion rate over the 4-year period between inspections. RG 1.147 stipulates the following condition on the use of Code Case N-597-1: "(5) For corrosion phenomena other than flow-accelerated corrosion, use of the Code Case is subject to NRC review and approval. Inspection plans and wall thinning rates may be difficult to justify for certain degradation mechanisms such as MIC and pitting."

The applicant stated that the maximum pit depth measured in the torus is 0.0685 inches (measured in 1992 in Bay 2). It was evaluated as acceptable by the design calculations at that time and was not based on calculation C-1302-187-E310-038. This bounding wall thickness in the torus remains. The criterion developed in 2002 for local thickness acceptance provides an easier method for evaluating as-found pits. The results were shown to be conservative versus the original ASME Code Section III and VIII requirements for the torus. The torus inspection program will be enhanced per IR 373695 to improve the detail of the acceptance criteria and margin management requirements by the ASME Code Section III criteria. The approach used in C-1302-187-E310-038 will be clarified as to how it maintains the code requirements. If ASME Code Case N-597-1 is required to develop these criteria for future inspections, staff review and approval will be obtained. It should also be noted that the program has established corrosion rate criteria and continues to monitor periodically to verify that they remain bounded.

The applicant's response clarified for the staff that pit depth acceptance criteria based on ASME Code Case N-597-1 had not been implemented and that if implementation should be contemplated the applicant will seek staff review and approval. The staff finds this clarification acceptable to resolve its concern about the use of ASME Code Case N-597-1.

From the applicant's response, the staff determined that there was minimal margin remaining between the current thickness and the minimum required thickness for the torus. During a followup onsite audit April 19-20, 2006, the staff discussed with the applicant the current condition of the torus, the pit depth acceptance criteria, and the scope of the coating inspection conducted every 4 years.

The applicant explained that the average remaining thickness of the torus is essentially the as-built thickness (0.385 inches). Five isolated pits, ranging from 0.042 to 0.068 inches in depth, are monitored and trended during each inspection. The applicant supplemented its earlier response to document this explanation.

The applicant further explained that pit depth acceptance criteria based on ASME Code Case N-597-1 had never been used to for acceptability of observed pitting. The current practice is to record and monitor all pits exceeding 0.040 inches in depth. The applicant supplemented its earlier response to indicate that, "Pits greater than 0.040 inches in depth shall be documented and submitted to engineering for evaluation."

In its letter dated May 1, 2006, the applicant supplemented its earlier response, committing (Commitment No. 27) to inspect the coating in all 20 bays of the suppression chamber (torus) during the period of extended operation. The frequency of inspection will be every other refueling outage for the current coating system. If the coating system is replaced, the inspection frequency and scope will be re-evaluated. The inspection scope will meet, as a minimum, the requirements of ASME Code Subsection IWE.

The applicant also committed (Commitment No. 27) to develop refined acceptance criteria and thresholds for entering coating defects and unacceptable pit depths into the corrective action process for further evaluation. These improvements will be incorporated into the inspection implementing documents prior to the next inspections and prior to the period of extended operation.

NRC inspectors conducted an inspection during the Oyster Creek October 2006 refueling outage. The team documented its findings in inspection report 05000219/20006013, dated January 17, 2007, (ML070170396). The inspection team reviewed supporting documentation and interviewed applicant personnel to confirm the adequacy of the license renewal conclusions from the visual inspections conducted in the torus. The inspection team noted that commitments for the torus were met. The visual test inspection procedures contained appropriate criteria for reporting nonconforming conditions and for dispositioning non-conforming conditions. On the basis of the inspection report findings, the staff determined that commitment 2 for the torus identified in the applicant's letter dated May 1, 2006, has been completed.

Based on the staff's understanding of (1) the current condition of the torus, (2) the applicant's plan to refine the pit depth acceptance criteria, and (3) the scope of the coating inspection conducted every 4 years, the staff concludes that the applicant's AMP for the suppression chamber (torus) provides reasonable assurance that the effects of aging will be adequately managed during the period of extended operation.

The staff reviewed those portions of the ASME Section XI, Subsection IWE Program for which the applicant claimed consistency with GALL AMP XI.S1 with the exception described below. Based on its review, the staff identified five open items (OIs) 4.7.2-1.1, 4.7.2-1.2, 4.7.2-1.3, 4.7.2-1.4, and 4.7.2-3, pertaining to aging management of primary containment (drywell shell). The staff resolution of these open items is discussed in Section 4.7.2.

Exception. In the LRA, the applicant stated an exception to the GALL Report recommendations in the "Program Description." Specifically, the exception stated:

> 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 10 CFR50.55a, 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.

The staff noted that the 1992 ASME Code Section XI, Subsection IWE, including 1992 addenda, was incorporated into 10 CFR 50.55a at the time the applicant was required to declare its inspection basis for the current 10-year IWE inspection interval. The applicant will incorporate the requirements specified in the ASME Code version incorporated into 10 CFR 50.55a 12 months before the start of the next 120-month inspection interval. As this incorporation is consistent with the recommendations in the GALL Report, the staff did not consider it an actual exception and finds it acceptable.

In its letters dated December 3, 2006 and December 15, 2006, the applicant revised the commitments for the IWE program based on the results of the October 2006 refueling outage NDE inspection activities associated with the primary containment drywell shell.

Specifically, during the 2006 drywell license renewal inspections, standing water was identified in contact with the drywell shell inside the trench in bay #5 as described below. Inspection and evaluation of the drywell shell concludes that because the water environment is alkaline and oxygen is limited during plant operation, the expected corrosion is insignificant. However, AmerGen will further enhance this aging management program to ensure potential drywell corrosion is detected and corrective actions are taken before a loss of the drywell intended function. The specific commitments which the applicant added are:

14. UT thickness measurements will be taken from outside the drywell in the sand bed region during the 2008 refueling outage on the locally thinned areas

examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.

15. Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sand bed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay #13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are Identified.

16. Perform visual inspections of the drywell shell inside the trenches in bay #5 and bay #17 and take UT measurements inside these trenches in 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

17. Perform visual inspection of the moisture barrier between the drywell shell and the concrete floor curb, installed Inside the drywell during the October 2006 refueling outage, in accordance with ASME Section XI, Subsection IWE during the period of extended operation.

After each inspection, UT thickness measurements results will be evaluated and compared with previous UT thickness measurements. If unsatisfactory results are identified, then additional corrective actions will be initiated, as necessary, to ensure the drywell shell integrity is maintained throughout the period of extended operation.

During the Advisory Committee on Reactor Safeguards (ACRS) meeting on February 1, 2007, the applicant committed to perform an engineering study prior to the period of extended operation in order to identify options to eliminate or reduce the leakage in the refueling cavity liner. The applicant also committed to perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

In its letter dated February 15, 2007, the applicant documented the commitments it made to the ACRS and revised Commitment 27 ASME Section XI, Subsection IWE. The applicant also added commitments to inspect the drywell trenches and the 10 drywell bays. The specific commitments and item numbers which the applicant added are:

18. AmerGen will perform a 3-D finite element structural analysis of the primary containment drywell shell using modern methods and current drywell shell thickness data to better quantify the margin that exists above the Code required minimum for buckling. The analysis will include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect Code margins. If the analysis determines that the drywell shell does not meet required thickness values, the NRC will be notified in accordance with 10 CFR 50 requirements.

19. AmerGen will perform an engineering study to investigate cost-effective replacement or repair options to eliminate or reduce reactor cavity liner leakage.

20. AmerGen is committed to perform visual and UT inspections of the drywell shell in the inspection trenches in drywell bays #5 and #17 during the Oyster Creek 2008 refueling outage (see item number 16 of AmerGen's IWE Program (Commitment 27), in its letter 2130-06-20426). AmerGen will extend this commitment and also perform these inspections during the 2010 refueling outage. In addition, AmerGen will monitor the two trenches for the presence of water during refueling outages. Visual and UT inspections of the shell within the trenches will continue to be performed until no water is identified in the trenches for two consecutive refueling outages, at which time the trenches will be restored to their original design configuration (e.g., refilled with concrete) to minimize the risk of future corrosion.

21. Perform the full scope of drywell sand bed region inspections prior to the period of extended operation and then every other refueling outage thereafter. The full scope is defined as:
    - UT measurements from inside the drywell (item number 1)
    - Visual inspections of the drywell external shell epoxy coating in all 10 bays (item number 4)
    - Inspection of the seal at the junction between the sand bed region concrete and the embedded drywell shell (item number 12)
    - UT measurements at the external locally thinned areas inspected in 2006 (item numbers 9 and 14)

Associated with these new commitments, the staff identified licensing conditions that require the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the next UFSAR update, as required by 10 CFR 50.71(e), following the issuance of the renewed license; perform full scope inspections of the drywell sand bed region every other refueling outage; and monitor drywell trenches every refueling outage to identify and eliminate the sources of water and receive NRC approval prior to restoring the trenches to their original design configuration. The staff finds the applicant's additional commitments for enhancing the ASME Section XI, Subsection IWE aging management program acceptable; therefore, the concern described in RAI 4.7.2-5 is resolved.

<u>Operating Experience</u>. The applicant stated, in the LRA, that ASME Section XI, Subsection IWE as described in the First 10-Year Containment (IWE) Inservice Inspection Program Plan and Basis is effective September 9, 1998, to September 9, 2008. Base line inspection of containment surfaces was completed in 2000 and a second inspection was completed in 2004. The 2004 inspection identified two recordable conditions, a loose locknut on a spare drywell penetration and a weld rod stuck to the underside of the drywell head. Engineering evaluation concluded that the stuck weld rod had no adverse impact on drywell head structural integrity and that the loose locknut did not affect the seal of the containment penetration.

The applicant stated that the upper region of drywell shell has experienced loss of material due to corrosion from water leakage into the gap between the containment and the reactor building in the 1980s. As a result the area is subject to augmented examinations by UT thickness measurements as required by ASME Code Section XI, Subsection IWE. UT measurements taken in 2004 showed that the drywell shell thickness meets ASME Code criteria and that the rate of corrosion is declining. Engineering evaluation of the UT results also concluded that the containment drywell, considering the current corrosion rate, is capable of performing its intended function through the period of extended operation. Further discussion is provided in LRA Section 4.7.2.

The applicant stated that the sand bed region also experienced loss of material due to corrosion attributed to the presence of oxygenated wet sand and exacerbated by the presence of chloride and sulfate in the sand bed region. As a corrective measure, the sand was removed and a protective coating was applied to the shell to mitigate further corrosion. Subsequent inspections confirmed that corrosion of the shell had been arrested. The coating is monitored periodically under the Protective Coating Monitoring and Maintenance Program. The staff evaluation of this program is addressed in SER Section 3.0.3.2.27.

The applicant stated that the suppression chamber (torus) and vent system were originally coated with Carboline Carbo-Zinc 11 paint. The coating is inspected every outage and repaired, as required, to protect the torus shell and the vent system from corrosion.

The applicant stated that from operating experience it had concluded that ASME Section XI, Subsection IWE is effective for managing aging effects of primary containment surfaces.

In PBD-AMP-B.1.27, the applicant expanded its discussion of operating experience to include industry operating experience and additional details of the plant-specific containment degradation. The applicant stated that industry operating experience had confirmed that corrosion had occurred in containment shells. INs 86-99, 88-82, and 89-79 described occurrences of corrosion in steel containment shells. GL 87-05 addressed the potential for corrosion of BWR Mark I steel drywells in the "sand pocket region." More recently, IN 97-10 identified specific locations where concrete containments are susceptible to liner plate corrosion. Plant operating experience shows that corrosion has occurred in several containment locations including 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 the ASME Section XI, Subsection IWE Program has identified and corrected the degradation. Experience with the ASME Section XI, Subsection IWE Program shows that it is effective in managing aging effects for the primary containment and its components.

The applicant included the following discussion and three examples of operating experience as evidence that the ASME Section XI, Subsection IWE Program effectively assures that intended functions will be maintained consistent with the CLB for the period of extended operation:

> The Oyster Creek ASME Section XI, Subsection IWE Program as described in Oyster Creek 10 Year Containment (IWE) Inservice Inspection Program Plan and Basis 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 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 (1) periodic UT inspections of the shell thickness at critical locations, (2) calculations which establish conservative corrosion rates, (3) projections of the shell thickness based on the conservative corrosion rates, and (4) 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.

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.

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 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).

In PBD-AMP-B.1.27, the applicant concluded that the operating experience of the ASME Section XI, Subsection IWE Program shows no adverse trend in performance. Problems identified will not cause significant impact to the safe operation of the plant, and adequate corrective actions were taken to prevent recurrence. The implementation of the ASME Section XI, Subsection IWE 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 program identify areas that need improvement to maintain performance of the program.

In its letter dated December 3, 2006, the applicant revised the operating experience section of the AMP B.1.2.7 to include experience from the October 2006 refueling outage. The additional operating experience included the following:

During the October 2006 refueling outage UT thickness measurements in the sand bed region were made inside the drywell at the same locations examined in 1996. The results of the statistical analysis of the 2006 UT data were compared to the 1992, 1994 and 1996 data statistical analysis results. Some of the 1996 data contained anomalies that are not readily justifiable but the anomalies did not significantly change the results. The comparison confirmed that corrosion on the exterior surfaces of the drywell shell in the sand bed region has been arrested.

In addition 106 UT thickness measurements were made in locally thinned areas, identified in 1992, from outside the drywell in the sand bed region. The 2006 UT thickness readings in the locally thinned areas are lower when compared to 1992 readings. This is largely due to using a more accurate UT instrument and the procedure used to take the measurements, which involved moving the instrument within the locally thinned area in order to locate the minimum thickness in that area. In addition the inner drywell shell surface could be subject to some insignificant corrosion due to water intrusion onto the embedded shell (see discussion below). Additional measurements of the locally thinned areas will be taken in 2008 using the same type of UT instrument to better correlate the measurements and confirm significant corrosion is not ongoing in the inner drywell shell surface.

During the 2006 refueling outage (1R21), UT thickness measurements were taken at the 4 elevations discussed above in accordance with the Oyster Creek ASME Section XI, Subsection IWE aging management program. The results of the UT thickness measurements indicated that no observable corrosion is occurring at elevations 51' 10" and 60' 10". A single location (Bay 15 -23L) of the 3rd elevation (50 '2") continues to experience minor corrosion at a rate of 0.66 mils/yr. The corrosion rate for the 4th elevation (87' 5") is now statistically insignificant and this elevation can be considered as no longer undergoing observable corrosion.

In addition UT measurements were taken on 2 locations (bay #15 and bay #17) at elevation 23' 6" where the circumferential weld joins the bottom spherical plates and the middle spherical plates. This weld joins plates that are 1.154" thick to the plates that are 0.770" thick. These two bays were selected because they are among those that have historically experienced the most corrosion in the sand bed region. At each location 49 UTs were taken above the weld on the 0.770" thick plate and 49 UTs were taken below the weld on the 1.154" thick plate. The minimum average thickness measured on the 0.770" thick plate is 0.766" and 1.160" on the 1.154" thick plate. The minimum measured local thickness on the 0.770" thick plate is 0.628" and on the 1.154" thick plate is 0.867". The minimum measured general and local thickness on each plate meets the minimum thickness required to satisfy ASME stress requirements with an adequate margin.

UT measurements were also taken on 2 locations (bay #15 and bay #19) at elevation 71' 6" where the circumferential weld joins the transition plates (referred to as the knuckle plates) between the cylinder and the sphere. This weld joins the knuckle plates, which are 2.625" thick to the cylinder plates, which are 0.640" thick. These two bays were selected because they also have historically experienced the most corrosion in the sand bed region. At each location 49 UTs were taken above the weld on the 0.640" thick plate and 49 UTs were taken below the weld on the 2.625" thick plate. The minimum measured average thickness on the 0.640" thick plate is 0.624" and 2.530" on the 2.625" thick plate. The minimum measured local thickness on the 0.640" thick plate is 0.449" and 2.428" on the 2.625" thick plate. The minimum measured general and local thickness on each plate meets the minimum thickness required to satisfy ASME stress requirements with an adequate margin.

Inner Drywell Shell in the Embedded Region

In 1986, as part of an ongoing effort at the Oyster Creek Generating Station to investigate the impact of water on the outer drywell shell, concrete was excavated at two locations inside the drywell (referred to as trenches) to expose the drywell shell below the Elevation 10'-3" concrete floor level to allow ultrasonic (UT) measurements to be taken to characterize the vertical profile of corrosion in the sand bed region outside the shell. The trenches (approximately 18" wide) were located in bays #5 and #17 with the bottom of the trenches at approximate elevations 8'-9" and 9-3" respectively (The elevation of the sand bed region floor outside the drywell is approximately 8'-11").

Following UT examinations in 1986 and 1988, the exposed shell in the trenches was prepped and coated and the trenches were filled with Dow Corning 3-6548 silicone RTV foam covered with a protective layer of Promatic low density silicone elastomer to the height of the concrete floor (Elevation 10'-3"). The assumption was that these materials would prevent water that might be present on the concrete floor from entering the trenches. Before the 2006 outage these materials had not been removed from the trenches since 1988.

During the October 2006 refueling outage, the filler material from the two trenches was removed to allow inspection of the shell in accordance with commitment number 27, item number 5. Upon removal of the filler material, approximately 5" of standing water was discovered in the trench located in bay #5. The trench area in bay #17 was damp; but no standing water was observed. Investigations concluded that the likely source of water was a deteriorated drainpipe connection and a void in the bottom of the Sub-Pile Room drainage trough, or condensation within the drywell that either fell to the floor or washed down the inside of the drywell shell to the concrete floor. Water samples taken from the trench in bay #5 were tested and determined to be non-aggressive with pH (8.40 - 10.21), chlorides (13.6 - 14.6 ppm), and sulfates (228 - 230 ppm). The joint between the concrete floor and the drywell shell had not been sealed to prevent water from coming in contact with the inner drywell shell. The degraded trough drainage system and the unsealed gap between the concrete slab/curb and the interior surface of the drywell shell was first discovered during this October 2006 refueling outage. This condition was entered into the Corrective Action Process (IR 546049). The following corrective actions were taken during the October 2006 refueling outage.

- Walkdowns, drawing reviews, tracer testing and chemistry samples were performed to identify the potential sources of water in the trenches.

- Standing water was removed from trench in bay #5 to allow visual inspection and UT examination of the drywell shell.

- An engineering evaluation was performed by a structural engineer, reviewed by an industry corrosion expert, and an independent third party expert to determine the impact of the as-found water on the continued integrity of the drywell.
- Field repairs/modifications were implemented to mitigate/minimize future

water intrusion into the area between the shell and the concrete floor. These repairs/modifications consisted of:

- Repair of the trough concrete in the area under the reactor vessel to prevent water from potentially migrating through the concrete and reaching the drywell shell rather than reaching the drywell sump,
- Caulking the interface between the drywell shell and the drywell concrete floor/curb to prevent water from reaching the embedded shell, and
- Grouting/caulking the concrete/drywell shell interfaces in the trench areas.

- The trench in bay #5 was excavated to uncover an additional 6" of the internal drywell shell surface for inspection and allow UT thickness measurements to be taken in an area of the shell that was embedded by concrete.

- Visual inspection of the drywell shell within the trenches was performed.

- A total of 584 UT thickness measurements were taken using a 6"x6" template (49 points) within the two trenches. Forty-two (42) additional UT measurements were taken in the newly exposed area in bay #5.

Visual examination of the drywell shell within the two trenches initially identified minor surface rust; with water in bay #5 and moisture in bay #17. After the surfaces were cleaned with a flapper wheel (lightly to avoid removing the metal) a visual examination of the shell was conducted in accordance with ASME Section XI, Subsection IWE. The visual examination identified no recordable (significant) corrosion on the inner surface of shell.

A total of 294 UT thickness measurements were taken in the bay #5 trench and 290 measurements were taken in the bay #17 trench during 2006 refueling outage. The results of the measurements indicated that the drywell shell in the trench areas experienced a reduction in the average thickness of 0.038"since 1986. AmerGen's evaluation concluded that the wall thinning was a result of corrosion on the exterior surface of the drywell shell in the sand bed region between 1986 and 1992 when the sand was still in place and corrosion was known to exist.

An engineering evaluation of the Oyster Creek inner drywell shell condition was prepared by a structural engineer and reviewed by an industry corrosion expert and independent third-party expert to determine the impact of the as-found water on the continued integrity of the drywell shell. The evaluation utilized water chemical analysis, visual inspections and UT examinations. It concluded that the measured water chemistry values and the lack of any indications of rebar degradation or concrete surface spalling suggest that the protective passive film established during concrete installation at the embedded steel concrete interface is still intact and significant corrosion of the drywell shell would not be expected as long as this benign environment is maintained. Therefore, since the concrete environment complies with the EPRI concrete structure guidelines, corrosion would not be considered significant within the Oyster Creek drywell and the water could remain in contact with the interior drywell shell indefinitely without having long term adverse effects.

More specifically, the results of this engineering evaluation indicate that no significant corrosion of the inner surface of the embedded drywell shell would be anticipated for the following reasons:

- The existing water in contact with the drywell shell has been in contact with the adjacent concrete. The concrete is alkaline which increases the pH of the water and, in turn, inhibits corrosion. This high pH water contains levels of impurities that are significantly below the EPRI embedded steel guidelines action level recommendations.

- Any new water (such as reactor coolant) entering the concrete-to-shell interface (now minimized by repairs/modifications implemented during this outage) will also increase in pH due to its migration through and contact with the concrete creating a nonaggressive, alkaline environment.

- Minimal corrosion of the wetted inner drywell steel surface in contact with the concrete Is only expected to occur during outages since the drywell is inerted with nitrogen during operations. Even during outages, shell corrosion losses are expected to be insignificant since the exposure time to oxygen is very limited and the water pH is expected to be relatively high. Also, repairs modifications implemented during the 2006 outage will further minimize exposure of the drywell shell to oxygen.

Based on the UT measurements taken during the 2006 outage of the newly exposed shell area in Bay 5 that has not been examined since it was encased in concrete during Initial construction (pre-1969), it was determined that the total metal lost based on a current average thickness measurement of 1.113" versus a nominal plate thickness of 1.154" is only 0.041" (total wall loss for both inside and outside of the drywell shell). Although no continuing corrosion is expected, but conservatively assuming that a similar wall loss could occur between now and the end of the period of extended operation, a margin of 336 mils to the 0.736" required wall thickness would exist.

As for the 0.676" thick embedded plate, conservatively assuming the plate has undergone corrosion of 0.041" to date, and will undergo similar wall loss between now and the end of the period of extended operation a margin of 115 mils against the required minimum general thickness of 0.479" required for pressure is provided.

The engineering evaluations summarized above confirmed that the condition identified during the 2006 outage would not impact safe operation during the next operating cycle. Also, a conservative projection (noted above) of wall loss for the 1.154" and 0.676" thick embedded shell sections indicates that significant margin is provided in both sections through the period of extended operation.

Although a basis is established that ongoing corrosion of the shell embedded in concrete should not be expected and repairs/modifications have been performed to limit or prevent water from reaching the internal surface of the drywell shell, AmerGen has now established that the existence of water in contact with the internal surface of the drywell shell and concrete at and below the floor elevation will be assumed to be a normal operating environment. AmerGen will further enhance the Oyster Creek ASME Section XI, Subsection IWE aging management program to require periodic inspection of the drywell shell subject to concrete (with water) environment in the internal embedded shell area and water environment within the trench area.

The staff reviewed the operating experience provided in the LRA, PBD, and the December 3, 2006, letter and interviewed the applicant's technical personnel. The staff concludes that the OCGS plant-specific operating experience is unique and not bounded by industry experience.

On the basis of its review of the operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's ASME Section XI, Subsection IWE Program will adequately manage the aging effects identified in the LRA and PBD-AMP-B.1.27 for which this AMP is credited.

The staff determined that the ASME Section XI, Subsection IWE Program described in LRA Section B.1.27, is consistent with the GALL AMP XI.S1, "ASME Section XI, Subsection IWE," with an exception and enhancements. However, operating experience indicated that the program had not been effective in managing the effects of aging in the drywell. The drywell degradation issue includes concerns associated with monitoring and eliminating water leakage, corrosion in the upper drywell region, corrosion in the former sand bed region, and pitting corrosion in the suppression chamber torus. The staff evaluated the applicant's Commitment 27, "ASME Section XI, Subsection IWE," which includes 21 items. In Section 4.7.2 in this SER, the staff reviewed applicant responses to five open items associated with the drywell degradation issue. On the basis of its evaluation of the program description, additional commitments, and the responses to the five open items, the staff determined that the ASME Section XI, Subsection IWE Program will provide assurance that the effects of aging on the drywell and torus will be adequately managed.

UFSAR Supplement. In LRA Section A.1.27 and letters dated April 4, May 1, June 23, December 3, and December 15, 2006, and February 15, 2007, the applicant provided the UFSAR supplement for the ASME Section XI, Subsection IWE Program. The staff reviewed this Section and determined that the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and found that this information reflects the resolution of the five open items and provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.24 ASME Section XI, Subsection IWF

Summary of Technical Information in the Application. In LRA Section B.1.28, the applicant described the existing ASME Section XI, Subsection IWF Program as consistent, with an exception and enhancements, with GALL AMP XI.S3, "ASME Section XI, Subsection IWF."

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function(s) of the structures. Inspection of the intake canal in 2001 identified some cracks and fissures, voids, holes, and localized washout of coatings that protect embankment slopes from erosion. The degradations were evaluated and determined not to impact the intended function of the intake canal (UHS). The degradations are inspected periodically and evaluated to ensure that the intended function of the intake canal is not adversely impacted.

The staff reviewed the operating experience provided in the LRA and PBD-AMP-B.1.32, and interviewed the applicant's technical personnel to confirm that the plant-specific operating experience revealed no degradation not bounded by industry experience.

On the basis of its review of the above plant-specific operating experience and discussions with the applicant's technical personnel, the staff concludes that the applicant's RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will adequately manage the aging effects identified in the LRA for which this AMP is credited.

UFSAR Supplement. In LRA Section A.1.32 and letter dated March 30, 2006, the applicant provided the UFSAR supplement for the RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program. The staff determined that the information in the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the applicant's RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, the staff determined that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation will make the AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.27 Protective Coating Monitoring and Maintenance Program

Summary of Technical Information in the Application. In LRA Section B.1.33, the applicant described the existing Protective Coating Monitoring and Maintenance Program as consistent with GALL AMP XI.S8, "Protective Coating Monitoring and Maintenance Program."

The Protective Coating Monitoring and Maintenance 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 sandbed region. Service Level I coatings are used in areas where coating failure could affect the operation of post-accident fluid systems adversely and thereby impair safe shutdown. OCGS was not originally committed to Regulatory Guide (RG) 1.54 for Service Level I coatings because the plant was licensed prior to the issuance of this RG in 1974. Currently, OCGS is committed to a modified version of this RG as described in the response to GL 98-04 and as detailed in the Exelon Quality Assurance Topical Report (QATR) NO-AA-10. Service Level II coatings provide corrosion protection and decontamination ability in areas outside of the primary containment subject to radiation exposure and radionuclide contamination. The Protective Coating Monitoring and Maintenance 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.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's evaluation of this AMP are documented in the Audit and Review Report Section 3.0.3.2.27.

During the audit the staff requested that the applicant clarify which coatings are credited for corrosion protection of metal surfaces. In its response, the applicant clarified that Service Level 2 coatings are used only for corrosion protection in the external drywell shell sand bed region. Similarly, while some Service Level 1 coatings are used to provide corrosion protection, the applicant does not credit them for corrosion protection for the internal surface of the drywell shell for license renewal purposes. An analysis has been performed which demonstrates that the upper portion of the drywell vessel will meet ASME Code requirements for the remaining life of the plant based on corrosion rates. The corrosion of the drywell shell above the sand bed region is considered a time-limited aging analysis (TLAA) and is further described in LRA Section 4.7.2. However, Service Level 1 coatings are credited for corrosion protection for the vent header and torus.

The applicant further stated that for loss of coolant accident debris generation and transport, the drywell coating is qualified for such an environment. The mass of coating released following a loss of coolant accident jet impingement was conservatively estimated at 47 pounds. No additional coating flaking was assumed due to the harsh environment because the coating is qualified. Coating within the vent system and torus is expected to contribute 0 pounds of debris to the suction strainer load following a loss of coolant accident. However, the analysis conservatively assumed 10 pounds of debris attributed to the vent system and torus coating.

The staff also requested that the applicant clarify whether any Service Level III coatings are credited for corrosion protection for license renewal. In its response, the applicant stated that Exelon Corporate Procedure ER-AA-330-008 in paragraph 2.7.3 defines Service Level III coatings as coatings used on any exposed surface area located outside containment whose failure could affect normal plant operation or orderly and safe plant shutdown adversely. Service Level III coatings are also used in areas outside the reactor containment where failure could affect the safety function of a safety-related structure, system, or component adversely. Specification SP-9000-06-004 in paragraph 3.2.1.c specifies the use of Service Level III coatings on structures/components subjected to a corrosive environment (e.g., liquid immersion, saltwater contact, underground burial, outdoor exposure, etc.). For license renewal Service Level III coatings are credited only for corrosion protection for the external surfaces of piping and fittings exposed to a soil (external) environment in the emergency service water (ESW) system, service water (SW) system, and roof drain and overboard discharge system (RDODS). These coatings are managed under the Buried Piping Inspection Program. Other than the Service Levels I and II coatings discussed in PBD-AMP-B.1.33, and the Service Level III coatings described in response to this question no other protective coatings are credited for corrosion protection for license renewal.

The staff also noted that the discussion in LRA Table 3.5.1, item 3.5.1-15, appears to identify a scope larger than that identified in the AMP description. The staff requested that the applicant clarify the scope of this program. In its response, the applicant stated that the structures or components and environments "rolled-up" into LRA Table 3.5.1 item 3.5.1-15 (reference LRA Table 3.5.2.1.1 for primary containment) include the following:

- access hatch covers - containment atmosphere (internal)
- downcomers - containment atmosphere
- drywell penetration sleeves - containment atmosphere (internal)
- drywell shell - containment atmosphere (internal) and indoor air (external)
- personnel airlock/equipment hatch - containment atmosphere (internal)
- suppression chamber penetrations - containment atmosphere (internal)
- suppression chamber ring girders - containment atmosphere (external)
- suppression chamber shell - containment atmosphere (internal)
- vent line, and vent header - containment atmosphere (internal) and indoor air (external)
- downcomers - immersed
- suppression chamber ring girders - immersed
- suppression chamber penetrations - immersed
- suppression chamber shell - immersed

The applicant stated that for Service Level I coatings the Protective Coating Monitoring and Maintenance Program is not used to manage loss of material for access hatch covers, drywell penetration sleeves, and personnel airlock/equipment hatches exposed to a containment atmosphere (internal) environment. Accordingly, LRA Table 3.5.2.1.1 for the primary containment will be revised to delete the Protective Coating Monitoring and Maintenance Program from these component types exposed to a containment atmosphere environment. For Service Level II coatings, the Protective Coating Monitoring and Maintenance Program is not used to manage corrosion for the vent line and vent header exposed to an indoor air (external) environment. Accordingly, LRA Table 3.5.2.1.1 and Table 3.5.1, item 3.5.1-15, will be revised to delete the Protective Coating Monitoring and Maintenance Program from this component type exposed to an indoor air environment.

In its letter dated April 17, 2006, the applicant stated that LRA Tables 3.5.2.1.1 and 3.5.1 will be revised to delete the Protective Coating Monitoring and Maintenance Program from line items to manage loss of material for access hatch covers, drywell penetration sleeves, and personnel airlock/equipment hatches exposed to a containment atmosphere (internal) environment and line items to manage corrosion for the vent line and vent header exposed to an indoor air (external) environment.

The staff finds the applicant's clarifications acceptable because they defined the scope of coatings credited for corrosion protection and also defined the coatings specifically monitored and maintained by the Protective Coating Monitoring and Maintenance Program for license renewal.

During its review of plant-specific operating experience related to containment degradation, the staff asked a number of questions about the implementation of the Protective Coating Monitoring and Maintenance Program for the exterior surface of the sand bed region and for the submersed interior surface of the torus. The staff's inquiries and assessments of the applicant's responses are documented in the evaluation of the applicant's ASME Section XI, Subsection IWE Program summarized in SER Section 3.0.3.2.23. The applicant made new commitments related to monitoring of these primary containment coatings in accordance with ASME Section XI, Subsection IWE (Commitment No. 33).

Subsequent to the audit, in response to RAI 4.7.2-1, by letter dated June 20, 2006, the applicant provided additional information regarding the coatings credited for corrosion mitigation for primary containment and activities associated with drywell shell corrosion. The staff's evaluation of the applicant's information and commitments is documented in SER Section 4.7.2.

Although the LRA did not identify any enhancements for the Protective Coating Monitoring and Maintenance Program, the applicant's program basis document, (PBD)-AMP-B.1.33, "OCGS Program Basis Document: Protective Coating Monitoring and Maintenance Program," Revision 0, identified the following enhancement to meet the GALL Report program elements:

Enhancement. The applicant identified an enhancement to its program elements "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria." Specifically, the enhancement stated that:

> 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 sand bed region, will be consistent with ASME Section XI, Subsection IWE requirements.

The staff requested that the applicant clarify what changes were necessary to make the Protective Coating Monitoring and Maintenance Program consistent with ASME Code Section XI, Subsection IWE requirements. In its response, the applicant stated that the requirements for coating inspections are included in OCGS specifications SP-1302-52-120, "Specification for Inspection and Localized Repair of the Torus and Vent System Coating," and IS-328227-004, "Functional Requirements for Drywell Containment Vessel Thickness Examination." These specifications do not invoke all of the requirements of ASME Code Section XI, Subsection IWE. The following requirements will be included in these inspection specifications:

(1) Torus and vent system internal coating inspections will be per Examination Category E-A and will require VT-3 visual examinations per IWE-3510.2. The inspected area shall be examined (as a minimum) for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Disposition of suspect areas shall be by engineering evaluation or correction by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of engineering evaluation.

(2) Sand bed region external coating inspections will be per Examination Category E-C (augmented examination) and will require VT-1 visual examinations per IWE-3412.1. The inspected area shall be examined (as a minimum) for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Disposition of suspect areas shall be by engineering evaluation or correction by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of engineering evaluation.

In its letter dated April 4, 2006, the applicant committed (Commitment No. 27) to the following:

> The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the protective coatings program. This commitment will be performed every other refueling outage prior to and during the period of extended operation.

On this basis, the staff finds this enhancement to the protective coating monitoring and maintenance program acceptable because it ensures that the requirements of ASME Code IWE related to coatings inspection will be implemented during the period of extended operation.

Operating Experience. In LRA Section B.1.33, the applicant explained that it has successfully identified indications of age-related degradation in Service Level I coatings prior to the loss of intended function(s) and has taken appropriate corrective actions through evaluation or repair in accordance with the Service Level I coatings procedures and specifications. Torus and vent header vapor space Service Level I coating inspections performed in 2002 found the coating in these areas in good condition. Inspection of the immersed coating in the torus identified blistering that 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 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 Service Level II coating effort completed in the 14R refueling outage has been effective in mitigating corrosion in the sand bed area. This effort was accomplished while the vessel thickness was sufficient to satisfy ASME Code requirements, so 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. To date, no age-related degradation has been detected in the sandbed region Service Level II coating.

In 2003, the replacement motor for the "A" recirculation motor was found to be top-coated with a non-design basis accident qualified coating on the motor housing, end bells, and stator. Engineering analysis concluded that negligible additional suction strainer debris loading will be created by the failure of this additional unqualified coating.

The staff reviewed the operating experience provided in the LRA and PBD and also interviewed the applicant's technical personnel. The staff concludes that the plant-specific operating experience with containment degradation is unique and not bounded by industry experience. The staff's review of operating experience led to a number of questions about the implementation of the Protective Coating Monitoring and Maintenance Program. As a result, the staff identified OI 4.7.2-3, regarding the extent of drywell shell coated surfaces examined during each inspection. The staff's evaluation and resolution of this OI is documented in SER Section 4.7.2.

UFSAR Supplement. In LRA Section A.1.33 and letters dated April 4, April 17, May 1, and June 23, 2006, the applicant provided the UFSAR supplement for the Protective Coating Monitoring and Maintenance Program. The staff reviewed this Section and determined that the UFSAR supplement provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) of primary containment will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.28 Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements Used in Instrument Circuits

Summary of Technical Information in the Application. In LRA Section B.1.35, the applicant

Section 3.5.2.2.1

PWR and BWR Containment:

- aging of inaccessible concrete areas
- cracks and distortion due to increased stress levels from settlement; reduction of foundation strength, cracking and differential settlement due to erosion of porous concrete subfoundations, if not covered by structures monitoring program
- reduction of strength and modulus of concrete structures due to elevated temperature
- loss of material due to general, pitting, and crevice corrosion
- loss of prestress due to relaxation, shrinkage, creep, and elevated temperature
- cumulative fatigue damage
- cracking due to stress corrosion cracking
- cracking due to cyclic loading
- loss of material (scaling, cracking, and spalling) due to freeze-thaw
- cracking due to expansion and reaction with aggregate and increase in porosity and permeability due to leaching of calcium hydroxide

Safety-Related and Other Structures and Component Supports:

- aging of structures not covered by structures monitoring program
- aging management of inaccessible areas
- reduction of strength and modulus of concrete structures due to elevated temperature
- aging management of inaccessible areas for Group 6 structures
- cracking due to stress corrosion cracking and loss of material due to pitting and crevice corrosion
- aging of supports not covered by structures monitoring program
- cumulative fatigue damage due to cyclic loading

Quality Assurance for Aging Management of Nonsafety-Related Components

Staff Evaluation. For component groups evaluated in the GALL Report, for which the applicant has claimed consistency with the GALL Report and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.5.2.2. Details of the staff's audit are documented in the Audit and Review Report. The staff's evaluation of the aging effects is discussed in the following sections.

3.5.2.2.1 PWR and BWR Containments

The staff reviewed LRA Section 3.5.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.1, which addresses several areas discussed below.

Aging of Inaccessible Concrete Areas. In LRA Section 3.5.2.2.1.1, the applicant stated that aging of inaccessible areas of concrete containments, with reference to the further evaluation in SRP-LR Section 3.5.2.2.1.1, is not applicable because OCGS has a Mark I steel containment. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable.

Cracks and Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength, Cracking and Differential Settlement Due to Erosion of Porous Concrete Subfoundations, If Not Covered by Structures Monitoring Program. In LRA Section 3.5.2.2.1.2, the applicant stated that cracks and distortion of concrete subfoundations, with reference to the further evaluation in SRP-LR Section 3.5.2.2.1.2, are not applicable because OCGS has a Mark I steel containment. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable.

Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature. The staff reviewed LRA Section 3.5.2.2.1.3 against the criteria in SRP-LR Section 3.5.2.2.1.3.

In LRA Section 3.5.2.2.1.3, the applicant addressed reduction of strength and modulus of concrete due to elevated temperatures.

SRP-LR Section 3.5.2.2.1.3 states that reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR concrete and steel containments. The implementation of 10 CFR 50.55a and ASME Code Section XI, Subsection IWL would not be able to identify the reduction of strength and modulus of concrete due to elevated temperature. Subsection CC-3400 of ASME Code Section III, Division 2, specifies the concrete temperature limits for normal operation or any other long-term period. The GALL Report recommends further evaluation of a plant-specific AMP if any portion of the concrete containment components exceeds specified temperature limits (i.e., general area temperature greater than 66 °C (150 °F) and local area temperature greater than 93 °C (200 °F)).

LRA Section 3.5.2.2.1.3 states that the normal operating temperature inside the primary containment drywell varies from 139 °F (at elevation 55') to 256 °F (at elevation 95'). The containment structure is a BWR Mark I steel containment, which is not affected by general area temperature of 150 °F and local area temperature of 200 °F. Concrete for the reactor pedestal and the drywell floor slab (fill slab) are located below elevation 55' and are not exposed to the elevated temperature. The biological shield wall extends from elevation 37' 3" to 82' 2" and is exposed to a temperature range of 139 °F to 184 °F. The wall is a composite steel-concrete cylinder surrounding the reactor vessel framed with 27 inches deep wide flange columns covered with steel plate on both sides. The area between the plates is filled with high-density concrete to satisfy the shielding requirements. The steel columns provide the intended structural support function and the encased high-density concrete provides shielding requirements. The encased concrete is not accessible for inspection. The elevated drywell temperature concern was evaluated as a part of the Integrated Plant Assessment Systematic Evaluation Program (SEP) Topic III-7.B. The evaluation concluded that the temperature would not adversely affect the structural and shielding functions of the wall. The elevated drywell temperature was also identified as a concern for the reactor building drywell shield wall. Further evaluation for this wall is discussed in SER Section 3.5.2.2.2.

The staff finds acceptable the applicant's further evaluation because the existing elevated temperature condition in the drywell will not impair the intended functions of the steel containment shell or the shielding concrete of the biological shield wall.

Based on the above, the staff concludes that the applicant has met the criteria of SRP-LR Section 3.5.2.2.1.3. For those LRA line items that apply to this SRP-LR section, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Loss of Material Due to General, Pitting and Crevice Corrosion. The staff reviewed LRA Section 3.5.2.2.1.4 against the criteria in SRP-LR Section 3.5.2.2.1.4.

In LRA Section 3.5.2.2.1.4, the applicant addressed loss of material due to general, pitting, and crevice corrosion in steel elements of accessible and inaccessible areas for BWR containment.

SRP-LR Section 3.5.2.2.1.4 states that loss of material due to general, pitting, and crevice corrosion could occur in steel elements of accessible and inaccessible areas for all types of PWR and BWR containments. The existing program relies on the ASME Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J Programs, to manage this aging effect. The GALL Report recommends further evaluation of plant-specific programs to manage this aging effect for inaccessible areas if corrosion is significant.

LRA Section 3.5.2.2.1.4 states 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 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 of exterior surfaces in areas where sand was removed, and an engineering evaluation to confirm the drywell structural integrity. In 1987, a corrosion monitoring process was established 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 Program and provide the following:

- 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
- demonstration that the minimum required shell thickness is in accordance with ASME Code

Additionally, the staff was notified of this potential generic issue that later became the subject of IN 86-99 and GL 87-05.

The applicant provided the following summary of the operating experience, monitoring activities, and corrective actions taken to ensure that the primary containment will perform its intended functions:

Drywell Shell in the Sand Bed Region. The drywell shell is fabricated from ASTM A-212-61T

Grade 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. The applicant performed a series of investigations to identify the source of the water and its leak path and concluded that the source of water was from the reactor cavity, which is flooded during refueling outages.

With the presence of water in the sand bed region, the applicant took extensive UT thickness measurements of the drywell shell to determine whether degradation had occurred. These measurements corresponded to known water leaks and indicated that wall thinning had occurred in this region.

With reduced thickness readings, the applicant obtained additional thickness measurements to determine the vertical profile of the thinning. In 1986, the applicant excavated two trenches in the drywell concrete floor in bays #5 and #17 where thinning was most severe because the sand bed region was inaccessible at that time. 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 with no floor level thinning showed no significant thinning in the embedded shell. Aside from UT thickness measurements by plant staff, an independent analysis by the EPRI NDE Center, and the GE Ultra Image III “C” scan topographical mapping system 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) the applicant obtained core samples of the drywell shell at seven locations in 1986. The core samples validated the UT measurements and confirmed that the corrosion of the drywell exterior was due to the presence of oxygenated wet sand and exacerbated by chloride and sulfate in the sand bed region. Contaminate concentration due to alternate wetting and drying of the sand also may have contributed to the corrosion. Therefore, the applicant concluded that the optimum method to mitigate the corrosion was by removal of the sand to break up the galvanic cell, removal of the corrosion product from the shell, and application of a protective coating.

Removal of sand was initiated during 1988 by the removal of 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 cut into the sand bed region through the shield wall. The work was finished in December 1992. After sand removal, the applicant found the concrete surface below the sand 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) removal of the loose debris from the concrete floor followed by rebuilding and reshaping of 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 inspected during refueling outages of 1994, 1996, 2000, and 2004. These inspections showed no coating failure or signs of deterioration. Therefore, the applicant concluded that corrosion in the sand bed region had been arrested and expected no further loss of material. 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.

In a letter dated December 3, 2006, the applicant provided information concerning the drywell inspections and ultrasonic (UT) measurements performed during the 2006 refueling outage. On the basis of visual inspections, which indicated no visible deterioration, the applicant confirmed that no further corrosion of the drywell shell is occurring from the exterior of the epoxy-coated sand bed region. On the basis of UT measurements of the drywell shell in the sand bed region from inside the drywell, the applicant confirmed that corrosion on the exterior surfaces of the drywell shell in the sand bed region has been arrested. On the basis of UT measurements taken in the trenches in drywell bays number #5 and #17, the applicant concluded that wall thinning of approximately 0.038" had taken place in each trench since 1986.

On the basis of 106 UT measurements taken on the outside of the drywell in the sand bed region in 2006, the applicant determined that the measured local thickness is greater that the local acceptance criteria of 0.409" for pressure and 0.536" for local bucking. The applicant decided that, since the 106 UT measurements could not be correlated directly with the corresponding 1992 UT data, it would enhance the ASME Section XI, Subsection IWE Program (B.1.27) to require UT measurements of the locally thinned areas in 2008 and periodically during the period of extended operation.

The staff reviewed the applicant's operating experience and proposed aging management activities to address degradation of the primary containment drywell area in the former sand bed region as part of its evaluation of the ASME Subsection IWE Program. The staff previously identified, in the SER, dated August 18, 2006, five OIs and found that the applicant had not provided sufficient information to conclude that the effects of aging for the primary containment would be adequately managed during the period of extended operation. The applicant provided additional information in the letters dated December 3 and 15, 2006, and February 15, 2007, including additional commitments (Commitment No.27), to the staff for review. Upon further evaluation, the staff concludes that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff's resolution of the open items is documented in Section 4.7.2 of this SER.

<u>Drywell Shell Above Sand Bed Region</u>. 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 provided a corrosion allowance by demonstrating, through analysis, that the original drywell design pressure was conservative. Amendment 165 to the OCGS 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 completely around the inside of the drywell at several elevations. At each elevation, a belt-line sweep took readings on as little as 1-inch centers wherever thickness changed between successive nominal 6-inch centers. 6" by 6" grids that exhibited the worst metal loss around each elevation were established by 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 of the adequacy of this inspection plan was obtained by a completely randomized inspection of 49 grids showing that all inspection locations satisfied ASME Code requirements. Evaluation of UT measurements taken through 2000 concluded that corrosion no longer occurs at two (2) elevations, the third elevation undergoes a corrosion rate of 0.6 mils per year, and the fourth 1.2 mils per year. The recent UT measurements (2004) confirmed that the corrosion rate continues to decline. The 2 elevations that previously exhibited no increase in corrosion continue the trend to no corrosion increase. The rate of corrosion for the third elevation decreased from 0.6 to 0.4 mils per year. The rate of corrosion for the fourth elevation decreased from 1.2 to 0.75 mils per year. After each UT examination campaign, an engineering analysis is performed to ensure the required minimum thickness through the period of extended operation. Thus, corrosion of the drywell shell is considered a TLAA further described in SER Section 4.7.2.

In a letter dated December 3, 2006, the applicant provided information concerning the drywell inspections and ultrasonic (UT) measurements performed during the 2006 refueling outage. On the basis of UT measurements taken at four elevation of the drywell, the applicant determined that:

- No observable corrosion is occurring at elevations 51' 10" and 60' 10".
- A single location at elevation 50' 2" continues to experience minor corrosion at a rate of 0.66 mils/year.
- The corrosion at elevation 87' 5" is statistically insignificant.

The applicant performed UT measurements at two locations at the circumferential weld that joins the bottom spherical plates and the middle spherical plates at elevation 23' 6". The applicant determined that the loss of material in the thinner plates is insignificant and is bounded by corrosion experience at other areas of the drywell above the sand bed region. The applicant determined that the thicker plates have not experienced any observable corrosion.

The applicant performed UT measurements at two locations at the circumferential weld that joins the transition plates, which are referred to as the knuckle plates, between the cylinder and the sphere at elevation 71' 6". The applicant determined that the loss of material in the thinner plates is insignificant and is bounded by corrosion experienced in other areas of the drywell above the sand bed region. Through its inspections, the applicant identified some reduced thickness in the thicker plate that could be attributed to several factors, including variations in original plate thickness, removal of material during original joint preparation, and corrosion. The applicant stated that even if the loss of material is attributed entirely to corrosion, the available thickness margin is adequate to ensure that the intended function of the drywell is not impacted before the next inspection planned for 2010.

The applicant committed to take UT measurements in 2010 at elevations 23' 6" and 71' 6" to confirm that corrosion is bounded by areas of the upper drywell that are monitored periodically. If corrosion in these locations is greater than areas monitored in the upper drywell, the applicant will perform UT inspection on a frequency of every other refueling outage (Commitment 27 Item numbers 10 and 11 in AmerGen Letter No. 2130-06-20358 dated July 7, 2006).

The applicant concluded that the corrective actions taken and continued monitoring of the drywell for loss material through the ASME Section XI, Subsection IWE, Protective Coating Monitoring and Maintenance, and 10 CFR Part 50, Appendix J Programs provide reasonable assurance that loss of material in inaccessible areas of the drywell will be detected prior to a loss of an intended function. Observed conditions with potential impact on an intended function are evaluated or corrected in accordance with the corrective action process. The ASME Section XI, Subsection IWE, Protective Coating Monitoring and Maintenance, and 10 CFR Part 50, Appendix J Programs are evaluated in SER Section 3.0.

The staff noted that the applicant had not addressed aging management of the portion of the drywell shell embedded in the drywell concrete floor. This area is inaccessible for inspection but potentially subject to wetting on both inside and outside surfaces. During the audit, the staff requested that the applicant submit its AMR for this inaccessible portion of the drywell shell.

The applicant stated that the embedded portion of the drywell shell is exempt from visual examination in accordance with IWE-1232. Pressure testing in accordance with 10 CFR Part 50, Appendix J, Type A test is credited for managing aging effects of inaccessible portions of the drywell shell consistent with the GALL Report.

The applicant identified that the GALL Report, Volume 2, item II.B1.1-2, AMP column states that loss of material due to corrosion is not significant if the following conditions are satisfied:

- concrete meeting the specifications of ACI 318 or 349 and use of the guidance of 201.2R for containment shell or liner
- concrete monitoring to ensure that it is free of cracks providing paths for water seepage to the surface of the containment shell or liner
- aging management of the moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management in accordance with ASME Section XI, Subsection IWE requirements
- prompt clean-up of water ponding on the containment concrete floor when detected

If any of these conditions cannot be satisfied, a plant-specific AMP for corrosion is necessary.

The applicant indicated that its AMR results satisfy these requirements and that a plant-specific AMP is not required for corrosion of the embedded drywell shell. The concrete meets the recommendations of ACI 318 and the guidance of ACI 201.2R. The drywell concrete floor will be monitored for cracks under the Structures Monitoring Program. OCGS design does not include a moisture barrier; however, the design provides a 9-inch high curb (minimum) around the entire drywell floor (except at two trenches) to prevent any contact between water accumulated on the floor and the drywell shell. The curb is considered part of the drywell concrete floor and inspected for cracking under the Structures Monitoring Program. The drywell floor is designed to slope away from the drywell shell towards the drywell sump for proper drainage. The sump level is monitored in the main control room in accordance with technical specifications, and actions are taken to ensure that technical specifications limits are not violated. If the sump fills and the overflow leak rate cannot be monitored, a plant shutdown will be required to regain leak rate monitoring capability and to determine the source of the leak.

The applicant further stated that during the investigation period to determine the extent of corrosion in the exterior surfaces of the sand bed region two trenches were excavated in the drywell concrete floor to expose the embedded drywell shell so that UT thickness measurements could be taken from inside the drywell in the sand bed region. Visual inspection and UT measurements did not identify corrosion as a concern on the exposed embedded drywell shell inside the drywell within the excavated trenches. The two trenches were sealed with an elastomer to prevent water intrusion into the embedded shell. Prior to the period of extended operation a one-time visual inspection of the embedded drywell shell within the two trenches will be performed by removal of the sealant and exposure of the embedded shell. Inspection and acceptance criteria will be in accordance with IWE. If visual inspection reveals corrosion that could impact drywell integrity, corrective actions will be initiated in accordance with the corrective action process to ensure that the drywell remains capable of performing its intended function. Following these inspections, the trenches will be resealed for continued protection of the embedded shell. In addition, one-time UT measurements will be taken and corrective actions initiated in accordance with the corrective action process to ensure that the drywell is capable of performing its intended function.

In its letter dated April 4, 2006, the applicant committed (Commitment No. 27) to the following: A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell steel remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. These surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE Program, or they will be restored to the original design configuration with concrete or other suitable material to prevent moisture collection in these areas.

In addition to its previous commitment to perform one-time visual examinations of the drywell shell in the areas exposed by the trenches in the bottom of the drywell, in its letter dated May 1, 2006, the applicant committed (Commitment No. 27) to taking one-time UT measurements to confirm the adequacy of the shell thickness in these areas, providing further assurance that the drywell will remain capable of performing its intended function. This commitment will be performed prior to the period of extended operation.

The applicant also noted that the inaccessible drywell shell in the sand bed region became accessible (from the outside surface) after removal of sand in 1992. The interface of the shell and the sand bed floor was cleaned, coated, and sealed with silicon sealant. The periodic coating inspection has not identified any coating degradation at the shell-concrete interface indicating corrosion in the embedded portion of the shell.

In a letter dated December 3, 2006, the applicant provided information concerning the drywell inspections and ultrasonic (UT) measurements performed during the 2006 refueling outage. During the outage, the applicant removed filler material from the two trenches to allow inspection of the embedded shell and found water in one of the trenches. The applicant concluded that the likely source of water was a deteriorated drainpipe connection and a void in the bottom of the Sub-Pile Room drainage trough, or condensation within the drywell that either fell to the floor or washed down the Inside of the drywell shell to the concrete floor.

The applicant drew water from the trench and determined the water to be non-aggressive with pH (8.40 - 10.21), chlorides (13.6- 14.6ppm), and sulfates (228 - 230 ppm). The applicant found that the joint between the concrete floor and the drywell shell had not been sealed to prevent water from coming in contact with the inner drywell shell. The applicant first discovered the degraded trough drainage system and the unsealed gap between the concrete slab curb and the interior surface of the drywell shell during the 2006 refueling outage. The following corrective actions were taken during the refueling outage.

- Walkdowns, drawing reviews, tracer testing, and chemistry samples were performed to identify the potential sources of water in the trenches.

- Standing water was removed from trench to allow visual inspection and UT examination of the drywell shell.

- An engineering evaluation was performed to determine the impact of the as-found water on the continued Integrity of the drywell.

- Field repairs and modifications were implemented to mitigate and minimize future water intrusion into the area between the shell and the concrete floor. These repairs and modifications consisted of:

    - Repair of the trough concrete In the area under the reactor vessel to prevent water from potentially migrating through the concrete and reaching the drywell shell rather than reaching the drywell sump.

    - Caulking the interface between the drywell shell and the drywell concrete floor and curb to prevent water from reaching the embedded shell.

    - Grouting and caulking the concrete/drywell shell interfaces in the trench areas.

- The trench was excavated to uncover an additional 6" of the internal drywell shell surface for inspection and allow UT thickness measurements to be taken in an area of the shell that was embedded by concrete.

- Visual inspection of the drywell shell within the trenches was performed.

- A total of 584 UT thickness measurements were taken within the two trenches. Forty-two (42) additional UT measurements were taken in the newly exposed area in bay #5.

The applicant determined that the measured water chemistry values and the lack of any indications of rebar degradation or concrete surface spalling suggest that the protective passive film established during concrete installation at the embedded steel/concrete interface is still intact. The applicant concluded that significant corrosion of the drywell shell would not be expected as long as the benign environment is maintained.

The applicant stated that it will further enhance the Oyster Creek ASME Section XI, Subsection IWE aging management program to require periodic inspection of the drywell shell subject to concrete (with water) environment in the internal embedded shell area and water environment within the trench area. Specific enhancements are:

- UT thickness measurements will be taken from outside the drywell in the sand bed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.

- Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sand bed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay #13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are identified.

- Perform visual inspection of the drywell shell inside the trench in bay #5 and bay #17 and take UT measurements inside these trenches in 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

- Perform visual inspection of the moisture barrier between the drywell shell and the concrete floor/curb, installed inside the drywell during the October 2006 refueling outage, in accordance with ASME Section XI, Subsection IWE during the period of extended operation.

After each inspection, the applicant will evaluate UT thickness measurements results and compare them with previous UT thickness measurements. If unsatisfactory results are identified, then applicant will initiate, as necessary, additional corrective actions to ensure the drywell shell integrity is maintained throughout the period of extended operation.

In its letter dated December 3, 2006, the applicant stated that LRA Table 3.5.1 will be revised to add the following Plant Specific Notes to Table 3.5.2.1.1:

10. Water environment for the drywell shell and the reinforced concrete slab (fill slab) was identified during 2006 in two trenches inside the drywell concrete floor. The source of water is most likely from leakage of treated water from plant equipment inside the drywell. Chemical tests of water samples in contact with concrete and the drywell shell indicate that the water is not aggressive (pH = 8.40 -10.21), (Chloride =13.6 - 14.6 ppm), and (Sulfate = 228 - 230 ppm).

11. The moisture barrier was added in 2006 to seal the junction of the embedded drywell shell and the concrete curb inside the drywell. The absence of the moisture barrier was identified as a potential path of water found in contact with the inner drywell shell embedded in the concrete drywell floor (fill slab).

12. 10 CFR Part 50, Appendix J, is not a credited aging management program because the moisture barrier is not the primary containment pressure boundary.

13. Oyster Creek operating experience identified that the reinforced concrete (fill slab) is

subject to ponding of water on the floor and water intrusion into the subsurface of fill slab. The source of water is most likely from leakage of treated water from plant equipment inside the drywell. Chemical tests of water samples in contact with the concrete indicate that the water is not aggressive (pH = 8.40 - 10.21, Chloride =13.6 - 14.6 ppm, and Sulfate = 228 - 230 ppm). The reinforced concrete (fill slab) is monitored for loss of material (spelling, scaling), change in material properties (loss of bond) and cracking due to corrosion of embedded steel. The aging effects and the aging management program are consistent with NUREG-1801, line item III.A1-4, for non-aggressive groundwater environment.

The staff concludes that the applicant will determine, based on the results of the inspection of the two trenches, the condition of the inaccessible portion of the drywell shell embedded in the drywell concrete floor prior to the period of extended operation, and that corrective actions will be taken as necessary if degradation is found. The staff finds the applicant's approach to aging management of the inaccessible portion of the drywell shell embedded in the drywell concrete floor acceptable.

In its evaluation of the applicant's ASME Section XI, Subsection IWE Program the staff evaluated the degradation history of the applicant's containment and the adequacy of its aging management commitments for the period of extended operation. Five open items and their resolutions are discussed in detail in SER Section 4.7.2. Based on the applicant's proposed aging management activities for the period of extended operation, the staff finds that the applicant has met the criteria of SRP-LR Section 3.5.2.2.1.4 for further evaluation and demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature</u>. LRA Section 3.5.2.2.1.5 states that loss of prestress of concrete containments is not applicable since OCGS has a Mark I steel containment. The staff finds acceptable the applicant's evaluation that this aging effect is not applicable since OCGS has a Mark I steel containment.

<u>Cumulative Fatigue Damage</u>. LRA Section 3.5.2.2.1.6 states that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.6 documents the staff's review of the applicant's evaluation of this TLAA.

<u>Cracking Due to Stress Corrosion Cracking (SCC)</u>. The staff reviewed LRA Section 3.5.2.2.1.7 against the criteria in SRP-LR Section 3.5.2.2.1.7.

In LRA Section 3.5.2.2.1.7, the applicant addressed cracking of stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds due to SCC.

SRP-LR Section 3.5.2.2.1.7 states that cracking due to SCC of stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds could occur in all types of PWR and BWR containments. Cracking due to SCC also could occur in stainless steel vent line bellows for BWR containments. The existing program relies on the ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J Programs to manage this aging effect. The GALL Report recommends further evaluation of additional appropriate examinations and evaluations to detect these aging effects for stainless steel penetration sleeves, penetration bellows and dissimilar metal welds, and stainless steel vent line bellows.

Section 4.7.2

4.7.1.3.4 Conclusion

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for the heater bay crane TLAA, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.2 Drywell Corrosion

4.7.2.1 Summary of Technical Information in the Application

In LRA Section 4.7.2, the applicant summarized the evaluation of drywell corrosion for the period of extended operation. The Mark I containment design includes an annulus (expansion gap) between the containment and the primary containment shield wall. The potential for degradation of the containment results from conditions that allow the introduction of water into the annulus. This potential for corrosion was first recognized when water was noticed coming from the sand bed drains in 1980. Corrosion was later confirmed by ultrasonic thickness measurements taken in 1986. Corrective action included establishing a minimum shell thickness. This was accomplished by demonstrating through analysis that the original drywell design pressure was conservative. The plant technical specifications were amended to reduce the drywell design pressure from 62 to 44 psig. The new design pressure, coupled with the measures to prevent water intrusion in the gap between the containment vessel and the shield wall concrete, allow the drywell vessel to meet ASME Code requirements for the remaining 40-year plant life. Analysis of the minimum wall thickness of the containment vessel satisfies the criteria of 10 CFR 54.3(a) and is thus a TLAA.

Regarding its analysis, the applicant stated that several corrective actions have been taken to ensure minimum wall thicknesses are maintained, including removal of sand from the sand bed region to break up galvanic action, removal of the corrosion product from the containment vessel, and application of a protective coating. In addition, OCGS performs a monitoring program to ensure that corrosion mitigation measures are effective and the required minimum wall thickness is maintained. The ASME Section XI, Subsection IWE Program ensures that the reduction in vessel thickness will not adversely affect the ability of the drywell to perform its safety function. Inspections conducted since 1992 demonstrate that as a result of corrective actions the corrosion rates are very low or in some cases have been arrested. Coated drywell surfaces do not show signs of or deterioration. Drywell vessel wall thickness measurements indicate a substantial margin to the minimum wall thickness, even when projected to the year 2029 using conservative estimates of the corrosion rates. Continued assessment of the observed drywell vessel thickness ensures that timely action can be taken to correct degradation that could lead to loss of the intended function.

The ASME Section XI, Subsection IWE Program assures that the drywell vessel thickness will not be reduced to less than the minimum required value in any future operation. Therefore, the effects of loss of material on the intended function of the drywell will be adequately managed in accordance with 10 CFR 54.21(c)(1)(iii) for the period of extended operation.

The ASME Section XI, Subsection IWE Program assures that the drywell vessel thickness will not be reduced to less than the minimum required value in any future operation. Therefore, the

effects of loss of material on the intended function of the drywell will be adequately managed in accordance with 10 CFR 54.21(c)(1)(iii) for the period of extended operation.

4.7.2.2 Staff Evaluation

The staff's review of LRA Section 4.7.2 identified areas in which additional information was necessary to complete the review of drywell corrosion. The applicant responded to the staff's RAI as discussed below.

4.7.2.2.1 Drywell Corrosion Sampling

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide information concerning the drywell corrosion existing during the late 1980s, and the new corrosion found during the subsequent inspections, provide the process used to establish confidence that the sampling done for identifying the areas of corrosion has been adequate.

In its response dated April 7, 2006, the applicant emphasized that it employs a robust process of establishing confidence that the nature and locations of sampling done and the areas considered for identifying the areas of corrosion have been adequate. The applicant stated that the elements of process were developed over several years and were defined in several technical documents submitted to the NRC in the 1990s. The applicant summarized the process as follows:

> Inspections using UT thickness measurements were conducted during refueling outages and outages of opportunity between 1986 and 1989 to establish and characterize the extent of corrosion of the drywell shell. The initial UT measurements were not based on a sampling process. Instead, the measurements were taken in areas that correspond to locations where water leakage was observed from the sand bed region drains. The UT measurements were then expanded around the drywell perimeter and vertically to establish locations affected by corrosion. Approximately 1000 UT thickness measurements were taken to identify thinnest areas. In addition, core samples of the drywell shell were taken at seven locations, believed to be representative of general wastage, to confirm UT results.
>
> Based on the results of these inspections, elevations 11'-3", 50'-2", and 87'-5" were identified for monitoring. Elevation 11'-3", which corresponds to the sand bed region, showed the highest corrosion rate in 1987 (up to 39.1 +/- 3.4 mils per year) based on 1986, and 1987 UT measurements. The high rate of corrosion in the sand bed region prompted corrective action of a physical nature that involved removal of the sand. As a result, corrosion of the drywell shell in the sand bed region was addressed differently than the upper region of the drywell.

The most critical region affected by the corrosion-related metal loss was the sand bed region of the drywell shell. The applicant provided a brief history of the UT measurements taken and actions taken to prevent or mitigate corrosion in this area as follows:

> The high rate of corrosion in the sand bed region was attributed to galvanic corrosion of the drywell shell caused by water retained in the sand because of lack of proper drainage. To reduce the corrosion rate, Oyster Creek initiated several corrective actions as described in the response to item (c) below. Evaluation of these corrective actions concluded that the most effective action to

reduce the corrosion rate is to remove the sand from the sand bed region and protect the drywell shell from additional corrosion by applying a protective coating.

Location of the UT measurements was not based on a sampling process. Instead, the locations were based on UT measurements taken at all accessible locations that correspond to the sand bed region from inside the drywell to establish the thinnest area. After the sand was removed in 1992, and prior to coating the shell, thickness measurements were taken in each of the 10 bays, from outside the drywell, to establish the minimum general and local thickness of the thinned shell. The measurements from inside the drywell showed that the minimum general thickness of the sand bed region is 0.800 inches, and the minimum local thickness is 0.618 inches. The measurements from outside the drywell in the sand bed region showed that the minimum thickness is generally greater than 0.800 inches. There were local areas where the thickness is less than 0.800 inches. However, the minimum average thickness in these areas is greater than 0.736 inches, which is required for satisfying ASME Code requirements. The minimum local thickness measured from outside the sand bed region is 0.603 inches. Considering measurement and instrument accuracies, it is concluded that locations examined from inside the drywell represent the condition of the sand bed region.

The results of these measurements and subsequent analysis, which considered all design basis loads and load combinations, confirmed that the "as found" condition of the drywell shell thickness satisfies ASME Section III minimum thickness requirements. Additional thickness measurements taken at all accessible locations (total of 19) from inside the drywell in 1992, 1994, and 1996 show no corrosion, or no significant corrosion (see Table-2). In addition, inspection of the protective coating on exterior surfaces of the drywell shell in the sand bed region, every other refueling outage, shows no degradation of the coating or the underlying shell."

A general trend of the average corrosion found in the sand-pocket area as provided by the applicant is shown in Figure 3 of the response. Figure 3 shows the growth of corrosion for the location of thinnest wall thickness. It shows an average thickness of 0.87 inch in December 1986 and approximately 0.8 inch in December 1992. After 1992 (i.e., after the application of an epoxy coating to the shell in the sand pocket area), the average thickness appears to have stabilized at 0.8 inch based on the readings taken in 1994 and 1996. After 1996, the applicant extrapolated the thickness to remain as 0.8 inch during the current licensing period and during the period of extended operation.

The applicant provided a status of corrosion of the upper region, above the sand bed region, and noted that based on the results of approximately 1000 UT measurements, the applicant continued to monitor elevations 50' 2" and 87' 5" in the regions above the sand bed region. A third elevation, 51' 10", was added to the scope of inspection after it was determined that the supplied plate thickness is slightly less than the adjacent 50' 2". For each elevation, UT measurements spaced approximately 1 inch within a 6-inch by 6-inch array were taken from inside the drywell around the entire perimeter of each elevation. Engineering evaluation of the UT results concluded that monitoring of 12 locations would represent the drywell shell condition and provide reasonable assurance that significant corrosion would be detected before a loss of an intended function. The applicant concluded that this is because the 12 locations, as described below, were selected considering the degree of drywell shell thinning and the minimum required thickness to satisfy ASME stress requirements:

- seven locations at 50' 2",
- three locations at elevation 87' 5", and
- two locations at elevation 51' 10".

These locations are inspected from the inside of the drywell shell on a frequency of every other refueling outage.

In response to an earlier concern from the staff regarding whether the inspected locations represent the condition of the entire drywell, in 1990, General Public Utilities Corporation (GPU) prepared a new random UT inspection plan (also known as augmented inspection) designed to address the concern. The plan was based on a nonparametric statistical approach using attribute sampling that assumes no prior knowledge of the distribution of corrosion above the sand bed region. It consisted of random UT testing of 57 plates using the 6-inch by 6-inch grid. The applicant-established acceptance criteria were that the mean and local thickness of the shell equals or exceeds the required minimum thickness, plus a corrosion allowance necessary to reach the next inspection.

The applicant noted that the inspection results using the new random inspection plan confirmed that previously monitored locations bound the condition of the drywell above the sand bed region, except one location at elevation 60' 10". This elevation was added to elevations 50' 2", 51' 10", and 87' 5" and has been monitored every other refueling outage since identified in 1992.

After describing the basis for the earlier staff acceptance of the applicant's program the applicant provided the results of further inspections:

> During a recent walkdown of the torus by the system engineer, water was found in three 5-gallon containers that were installed to collect water leakage from the sand bed drains. Two of the 3 containers were found nearly full. The third container was approximately half full. Inspection of the drain lines showed that the lines were dry and that water in the containers was not due to a water leakage. The containers were closed such that their overflow was unlikely as confirmed by no water ponding on the floor.

Thus, the applicant concluded with reasonable assurance that the volume of water was limited to what is contained in the containers, and attempted to justify that the small amount of water was not expected to have significant impact on the drywell shell and on the coating of the shell, since the coating is designed for a submerged environment. The applicant noted that further inspection of the sand bed region coating conducted in 2004 did not indicate coating degradation or indications of drywell shell corrosion. Similarly, UT examinations on the upper region of the drywell showed a decrease in the corrosion rate since the previous inspection in 2000. Thus, the applicant concluded that the small volume of water found in the bottles should not have created an environment that would result in significant corrosion to the drywell shell.

OCGS Issue Report No. 00470325 was issued, in accordance with the corrective action process, to investigate the source of water and evaluate its impact on the drywell shell. Based on the discussion above, and as indicated in the tables supplied in response to item (d) below, the applicant concluded that drywell corrosion is effectively managed both during the current and proposed renewed terms of plant operation. The monitored locations under the current term were subjected to extensive UT measurements conducted over several years. The staff finds the sampling methodology to identify these locations, and the results of inspections, acceptable for the current term. The applicant stated that the same locations will be inspected during the extended period of operation.

In summary, the applicant emphasized that OCGS has conducted extensive examinations to identify the cause of drywell corrosion, employed a robust sampling process, quantified with reasonable assurance the extent of drywell shell thinning due to corrosion, and assessed its impact on the drywell's structural integrity.

In addition, the applicant stated that water intrusion into the gap between the drywell shell and the drywell shield wall was identified as the cause for corrosion. Corrective actions have been taken to mitigate corrosion in the sand bed region and in the upper region of the drywell. Corrosion of the drywell shell in the sand bed region has been arrested. These actions also have effectively reduced the rate of corrosion to a negligible amount in the upper region, as demonstrated by UT thickness measurements. OCGS and its consultants performed stress and buckling analyses considering all design-basis loads and load combinations. The results of these analyses indicated that buckling controls the minimum drywell shell thicknesses in the sand bed region, while areas above the sand bed region are controlled by accident pressure membrane stresses. In both cases, the minimum measured drywell shell thickness satisfied ASME Code Section III requirements.

<u>Open Item 4.7.2-1.1: Location of UT Measurements</u>

The staff's review of the applicant's response, including Figure 3 and Tables 1 and 2, determined that UT measurements taken in the spherical portion of the drywell shell adequately represent the upper spherical area. However, there were no measurements taken in the lower portion of the spherical area above the sand-pocket area. To ensure that the spherical portion of the drywell shell is properly represented in the database, additional UT measurements taken approximately at or above the junction of the 0.722 inch and 1.154 inch thick plates would be desirable. Likewise, additional UT measurements should be taken on the cylindrical portion of the drywell shell at about 71' 6" (i.e. at the junction of the 0.640 inch plate and the thickened plate in the knuckle area). The staff requested that the applicant clarify its UT sampling plan in context of the entire drywell shell assessment.

In its response dated June 20, 2006, the applicant stated:

> A review of the drywell fabrication and installation details show that the welds that attach the 0.770 inches (the correct thickness is 0.770 inches, not 0.722 inch as indicated in the meeting notes) nominal plates to the 1.154 inch nominal plates at elevation 23 ft 6 7/8 inch are double bevel full penetration welds. The external edge of the 1.154 inches plates is tapered to 3 to 12 minimum as required by ASME Section VIII, Subsection UW-35, while the internal edge of the 1.154 inch plates are flush with the 0.770 inch plates. Thus there are no ledges that could retain water leakage and result in more severe corrosion than in areas included in the inspection program. Also, this joint is located below the equatorial center of the sphere. Therefore, in the event that water may run down the gap between the drywell shell and the concrete wall it would not collect on this joint.
>
> In 1991, Oyster Creek performed random inspections of the drywell shell. Ultrasonic testing inspections were conducted at 19 locations on either the 1.154 inch thick plates or on the 0.770 inch thick plates. The UT measurements were taken on a 6 inch x 6 inch grid (49 UTs) at each location. The UT measurement

results show that thinning of the plates at these locations is less severe than the areas that are included in the corrosion-monitoring program. For this reason, the transition area was not added to the corrosion-monitoring program. Based on the above, AmerGen concludes that areas monitored under the drywell corrosion monitoring program bound the transition (from 1.154 inches to 0.770 inch thick plates) area of the drywell shell. Nevertheless, UT measurements will be taken on the 0.770 inch thick plate, just above the weld, prior to entering the period of extended operation.

The measurements will be conducted at one location using the 6 inch x 6 inch grid. A second set of UT measurements will be taken two refueling outages later at the same location. The results of the measurements will be analyzed and evaluated to confirm that the rate of corrosion in the transition is bounded by the rate of corrosion of the monitored areas in the upper region of the drywell. If corrosion in the transition area is found to be greater than areas monitored in the upper region of the drywell, UT inspections in the transition area will be performed on the same frequency as those performed on the upper region of the drywell (every other refueling outage).

Similarly, a review of fabrication and installation details of the containment drywell shell shows that the weld that connects the 2.625" knuckle plates to the 0.640"cylinder plates at elevation 71 ft 6 inch is a double bevel full penetration weld. The edges of the 2.625 inch plates were fabricated with a 3 to 12 taper to provide a smooth transition from the thicker to the thinner plate as required by ASME Section VIII, Subsection UE-35. Thus there are no ledges that could retain water leakage and result in more severe corrosion than the areas included in the inspection program.

In 1991, Oyster Creek performed random inspections of the drywell shell. Ultrasonic testing (UT) inspections were conducted at 18 locations on the 2.625 inch thick knuckle plate and at four (4) locations on the 0.640 inch thick cylinder plate. The UT measurements were taken on a 6 inch x 6 inch grid (49 UTs) at each location. The UT measurement results showed that thinning of the plates at these locations was less severe than the areas that are included in the corrosion monitoring program. For this reason the knuckle area was not added to the corrosion monitoring program. Based on the above, AmerGen concludes that areas monitored under the drywell corrosion monitoring program bound the knuckle area of the drywell shell. However, UT measurements will be taken above the 2.625 inch knuckle plate in the 0.640 inch thick plate prior to entering the period of extended operation.

The staff views random sampling of UT measurement as being valuable if the likelihood of corrosion is almost equal at every place in the region considered for UT measurements. If the geometry of the region and water flow in the air gap is such that suggest itself that one area is more likely to have corrosion than the other, then the sampling plan has to consider those areas which are more likely to have corrosion in addition to the randomly selected areas. If the water flow in the air gap is high, the applicant's argument that the weld transition will not allow water accumulation will be accurate. However, if the water flow is slow, this may not hold true. During the forthcoming outage, the applicant plans to perform UT measurements at one location on each of the transition areas.

The staff believes that examination of 4 locations in each transition area is needed. The locations along the thickness transition should be consistent with the areas that have large water accumulation and corrosion in the sand bed region. This was identified as open item (OI) 4.7.2-1.1 in the SER, dated August 18, 2006.

The applicant updated the IWE Program commitments in its December 3, 2006, submission (pages 73 and 74, items 10 and 11) with four separate sets of UT thickness measurements of the drywell shell at two areas of transition between shell plate thicknesses using a 6”x6” grid (*i.e.*, four separate 49-point UT sets at the transition at elevation 23’ 6 7/8” and four sets of UTs at elevation 71’-6”). The specific locations selected will be based on previous operational experience (*i.e.*, biased toward areas that have experienced corrosion or exposure to water leakage). These measurements will be at the same locations prior to the period of extended operation and at the second refueling outage after the initial inspection. If corrosion in these transition areas is greater than in areas monitored in the upper drywell, UT inspections in the transition areas will be on the same frequency as those in the upper drywell (every other refueling outage). Of these four locations there were UT measurements at two for each transition area during 2006 outage. These first-time readings show that the mean and individual thicknesses meet acceptance criteria with adequate margin. There will be UT measurements in the remaining two locations at each transition area during the next outage prior to the period of extended operation.

The applicant’s actions to include in the program UT measurement of shell areas that may experience increased rates of corrosion resolve the staff concern. The basis for the staffs conclusion is that the UT measurements as described should provide an adequate data base to confirm whether the random sampling program for UT measurements is reasonably representative.

The staff, however, noted an inconsistency in license renewal Commitment 27, “ASME Section XI, Subsection IWE,” items 10 and 11, where it states that the UT measurements will be at one location. In discussions on December 13, 2006, the applicant indicated that this statement was an editorial error. In a subsequent letter dated December 15, 2006, AmerGen corrected the error in the license renewal commitment list. Open Item 4.7.1-1.1 is closed.

In its letter dated February 15, 2007, the applicant revised a commitment (Commitment No. 27) by adding Item 21, which states that the performance of the full scope of drywell sand bed region inspections will be conducted every other refueling outage. The staff identified this commitment item as a license condition.

<u>Open Item 4.7.2-1.2: Drywell Shell Embedded Concrete</u>

In the sand pocket region of the drywell shell, the most susceptible bays are incorporated in the sampling. However, the staff believes that readings should be taken vulnerable locations and that UT techniques are reliable. The first issue is addressed below and the second issue is addressed as part of UT Measurement Issues.

The first item is that it is not clear if the junction between the 1.154- and the 0.676-inch plate at the elevation 6' 10.25" is represented in the sampling. Though this point is below the bottom of the sand-pocket area in contact with the alkaline environment of concrete, in the past (before sealing of the junction between the steel and the concrete), this area would have been subjected to the same type of contaminated water as the drywell in the sand-pocket area and is considered as a suspect area for corrosion. The staff requested that the applicant justify why this area should not be included in the sampling plan.

In its response dated June 20, 2006, the applicant noted that a review of the drywell construction and fabrication details shows that the drywell skirt is welded to the 1.154 inch thick plate below the sand bed floor. This thick plate is welded to the 0.676 inch plate at elevation 6' 10.25". The purpose of the skirt, which is also embedded in concrete, was to support the drywell during construction. The presence of the skirt prevents moisture intrusion into the 0.676 inch plate. Quoting the provisions of GALL Report the applicant noted:

- Concrete meeting the specifications of ACI 318 or 349 and the guidance of 201.2R was used for the containment shell or liner.

- The concrete is monitored to ensure that it is free of cracks that provide a path for water seepage to the surface of the containment shell or liner.

- The moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with ASME Code Section XI, Subsection IWE requirements.

- Water ponding on the containment concrete floor are not common and when detected are cleaned up in a timely manner.

Additionally, AmerGen contracted with Structural Integrity Associates, Inc. (SI) to provide an assessment of corrosion of the embedded drywell shell in the sand bed region. The applicant asked SI to address corrosion of the drywell shell prior to 1992, when the shell was potentially exposed to moisture retained by the sand, and post 1992 after the sand was removed and other mitigative actions were taken to prevent water intrusion into the embedded shell. The assessment results can be summarized as follows:

- Corrosion of the Embedded Drywell Shell prior to 1992: The corrosion of the drywell shell in the sand bed region was caused by the moisture trapped in the sand bed due to water leakage into the region. The source of leakage was determined to be the reactor cavity, which is filled with demineralized water during refueling outages. The water passed over the Firebar-D coating that was applied to the drywell shell to allow for formation of the required seismic gap between the drywell shell and the encircling concrete shield wall. The Firebar-D material is a magnesium oxychloride compound. The drywell was erected onsite and exposed to salt air environment during construction, which could also introduce contaminants to the sand bed environment. Chemistry test results on wet sand conducted in 1986 indicated that the leachate from the moist sand had a pH of 8.46 and contained only 45 ppb chlorides and <17 ppb sulfates.

- As noted in EPRI Report 1002950, this water is not aggressive to concrete since the pH is greater than 5.5, the chlorides are less than 500 ppm and sulfates are less than1500 ppm. This means that the wetted concrete environment will provide a high pH environment that will protect the embedded shell from corrosion. Additionally, the corrosion rates calculated for the carbon steel plugs removed from the drywell shell in the sand bed region were comparable to carbon steel exposed to typical waters over a similar temperature range. While an increase in the salinity and impurity of the water will increase the kinetics of the corrosion reaction by increasing the electrolyte conductivity and can alter the form of corrosion experienced by steel (e.g., from general corrosion to pitting corrosion), impurities such as chloride and sulfate are not fundamentally involved in the corrosion anodic and cathodic reactions. In fact, increasing the salinity of the water decreases the dissolved oxygen content of the water and, thus, reduces the concentration of cathodic reactant present for the corrosion reaction.

The applicant stated that it is reasonable to assume that the corrosion rate of the embedded shell is significantly less than the shell in contact with the sand bed for two primary reasons:

- The carbon steel in the embedded region is in contact with high pH concrete that allows the creation of a passive film on the steel surface. That is, the presence of abundant amounts of calcium hydroxide and relatively small amounts of alkali elements, such as sodium and potassium, gives concrete a very high alkalinity (e.g., pH of 12 to 13). In fact thermodynamic calculations reveal no corrosion of iron (steel) above pH 10 at room temperature.

- Uniform corrosion will tend to occur when some surface regions become anodic for a short period, but their location and that of the cathodic regions constantly change. For example, general corrosion/rusting of mild steel will occur when there is a uniform supply of oxygen available across the surface of the steel and there is a uniform distribution of defects in the oxide film as is usually the case in the non-protective films formed on unalloyed steel. In the absence of areas of high internal stress (e.g., cold-worked regions) or segregated zones (e.g., non-uniform distributions of sulfide inclusions), a number of anodic regions will develop across the surface. Some areas will become less active while new anodic regions become available. Therefore, overall attack takes place at a number of anodic sites whose positions may change, leading to general rusting across the surface.

  If the supply of oxygen is not uniform across a surface, then any regions that are depleted in oxygen will become anodic as the case of moist sand in contact with the drywell steel. The remainder of the drywell surface including the embedded steel has oxygen available to it and therefore acts as a large cathodic area. When the cathodic area is larger, local attack will occur in the smaller anodic region. This phenomenon is referred to as differential aeration.

  Therefore, due to the creation of a differential aeration cell, the adjacent carbon steel in contact with the moist sand bed acts as an anode that sacrifices itself to the benefit of the steel in the embedded region. That is, the corrosion of the sand cushion steel preferentially corrodes as galvanically coupled to the embedded steel.

The applicant, also discussed potential for corrosion of the embedded drywell shell after 1992. In response to RAI 4.7.2-1(c) AmerGen described several corrective actions taken to mitigate corrosion of the drywell shell. These mitigative actions are designed to minimize water intrusion into the sand bed region, provide for an effective drainage of the region in the event of water leakage and monitor the drains to detect leakage. If water leakage is observed coming from the sand bed region drains, numerous investigative and corrective actions will be taken. In addition, a silicone seal is applied at the junction of drywell shell and the sand bed concrete floor to prevent intrusion of moisture into the embedded drywell shell. These actions mitigate subsequent long term significant corrosion of the embedded shell for the following two reasons:

- The general lack of two of the four necessary fundamental parameters necessary for any form of corrosion to occur, an electrolyte, (i.e., moisture) and the cathodic reactant (i.e., oxygen), while only the lack of one fundamental parameter is sufficient to prevent corrosion. Sealing off the embedded steel will prevent any refreshment of moisture in the embedded region and any residual moisture will not support any subsequent corrosion once all the dissolved oxygen is consumed in the cathodic corrosion reaction. The cessation of the corrosion reaction will occur regardless of the presence of contaminants that may be dissolved in the water (e.g., chloride, sulfate, etc.) since although these impurities can affect the kinetics of the corrosion reaction, they do not participate in the cathodic reduction reaction. Once the cathodic reaction is stopped, corrosion is stopped. Intermittent wetting and aeration of the embedded steel would produce only minimal additional corrosion.

- The presence of concrete in contact with the embedded steel will mitigate corrosion even if sufficient moisture and oxygen are available due to the spontaneous formation of a thin protective oxide passive film on the embedded steel surface in the highly alkaline solution of the concrete. As long as this film is not disturbed, it will keep the steel passive and protected from corrosion.

In summary, the applicant noted that AmerGen has extensively investigated drywell corrosion, including the embedded shell. A review of plant operating and industry experience indicates that corrosion of embedded steel in concrete is not significant because it is protected by the high alkalinity in concrete. Corrosion could only become significant if the concrete environment is aggressive. Also, historical data shows that the environment in the sand bed region is not aggressive, and thus any water in contact with the embedded shell is not aggressive. The data also shows that corrosion of the drywell shell in the sand bed region is due to galvanic corrosion and impurities such as chlorides and sulfates are not fundamentally involved in the corrosion anodic and cathodic reactions. Thus, only limited corrosion would be anticipated for the drywell embedded shell.

AmerGen has also committed to a comprehensive drywell corrosion-monitoring program for the period of extended operation. The program includes mitigative measures to prevent water intrusion into the sand bed region. The sand bed region concrete floor is sealed with epoxy coating. The junction between the sand bed region concrete floor and the drywell shell was sealed in 1992 to prevent moisture from impacting the embedded shell. Thus, additional significant corrosion of the embedded shell is not expected because of lack of moisture and depleted oxygen. AmerGen will also take specific actions if water leakage is detected in the sand bed region drains.

For all of the above reasons, the applicant stated that the corrosion rate for the embedded drywell shell is less than the corrosion rate of the sand bed region of the drywell shell. Also, direct monitoring of the drywell shell in the sand bed region adequately bounds any corrosion in the drywell embedded shell.

AmerGen concluded that corrosion monitoring of the sand bed region of the drywell shell is bounding with respect to corrosion that may have occurred on the drywell embedded shell prior to 1992. After 1992, corrosion of the embedded shell has not been significant because of the mitigative measures implemented and the robust drywell corrosion AMP and the applicant concluded that this trend of no significant corrosion will continue during the period of extended operation.

The staff understands AmerGen's technical reasons to support the applicant's view that the inaccessible portion of the drywell shell (i.e. embedded between the concrete floor inside, and concrete outside) is not likely to be subject to the same type of severe corrosion as experienced in the sand bed area. However, the experience of general corrosion in the liner plates embedded in concrete of a number of PWR and BWR containments suggests that certain irregularities during the construction (i.e. foreign objects or voids in the concrete) could trigger corrosion that is not arrested later by the concrete environment. This is particularly significant for the plates potentially subject to water seepage. The applicant's position that the uniformly reduced thickness used in the GE analysis compensates for any corrosion that may have occurred before the area was sealed in 1992 has some validity. Because the staff was still evaluating, this item was identified as OI 4.7.2-1.2 in the SER, dated August 18, 2006.

During the October 2006 refueling outage, the applicant inspected the embedded drywell shell in the trenches in bays #5 and #17 after removing the filler material in the trenches and observed approximately 5 inches of standing water in the trench located in bay #5, and the trench in bay #17 was damp. Investigations concluded that the likely water sources were a deteriorated drainpipe connection and a void in the bottom of the Sub-Pile Room drainage trough or condensation within the drywell that either fell or washed down the inside of the drywell shell to the concrete floor. Water samples taken from the trench in bay #5 were tested and determined to be non-aggressive in pH (8.4 – 10.21), chlorides (13.6 – 14.6 ppm), and sulfates (228 – 230 ppm).

The applicant entered the condition into the corrective action process. Several corrective actions included repair of the trough concrete in the area under the reactor vessel to prevent water from migrating through the concrete and reaching the drywell shell and caulking of the interface between the drywell shell and the drywell concrete floor/curb including the trench areas. The trench bay in bay #5 also was excavated to uncover an additional 6 inches of the internal drywell shell surface for inspection and UT thickness measurement. A total of 584 UT thickness measurements were taken using a 6”x6” template within the two trenches. Forty-two additional UT measurements were taken in the newly exposed area in bay #5.

Visual examination of the drywell shell within the two trenches detected minor surface rust with no recordable corrosion on the inner surface of the shell. The UT measurements indicated that the drywell shell in the trench areas had experienced a 0.038” reduction in average thickness since 1986. Amergen concluded that the wall thinning was a result of corrosion on the exterior surface of the drywell shell in the sand bed region between 1986 and 1992 when the sand was still in place and the corrosion was known.

An engineering evaluation to determine the impact of the as-found water on the continued integrity of the drywell concluded that the measured water chemistry values and the lack of any indications of rebar degradation or concrete surface spalling suggest that the protective passive film established during concrete installation at the embedded steel/concrete interface is still intact and that significant corrosion of the drywell shell is not expected as long as this benign environment is maintained. More specifically, this engineering evaluation indicates that no significant corrosion of the inner surface of the embedded drywell shell is anticipated for the following reasons:

- The water in contact with the drywell shell has been in contact with the adjacent concrete, which is alkaline, increases the pH of the water, and inhibits corrosion. This high-pH water contains levels of impurities significantly below the EPRI embedded steel guidelines action level recommendations.

- Any new water (*e.g.*, reactor coolant) entering the concrete-to-shell interface (now minimized by repairs) also increases pH by its migration through and contact with concrete, creating a non-aggressive, alkaline environment.

- Minimal corrosion of the wetted inner drywell steel surface in contact with concrete is expected only during outages because the drywell is inerted with nitrogen during operations. Even during outages, shell corrosion losses are expected to be insignificant as the exposure time to oxygen is very limited and the water pH is expected to be relatively high. Also repairs/modifications during the 2006 outage will further minimize exposure of the drywell shell to oxygen.

After the UT thickness measurement during the 2006 outage of the newly-exposed shell area in bay #5, which had not been examined since initial construction, a reduction of average shell thickness of 0.041” was observed. The applicant maintains that, although no continuing corrosion is expected, there is sufficient margin for both the 1.154” thick plate and the 0.676” thick plate even assuming the same reduction until the end of the period of extended operation.

The applicant also has enhanced the AMP to require periodic inspection of the drywell shell subject to concrete (with water) environments in the internal embedded shell area. After each inspection, UT thickness measurements will be evaluated and compared to previous UT thickness measurements. If results are unsatisfactory, additional corrective actions, as necessary, will maintain drywell shell integrity throughout the period of extended operation.

To investigate the feasibility of state-of-the-art non-destructive examination techniques to determine the condition of the embedded region, the applicant contacted EPRI and other utility owners that use these techniques. After discussions and findings, the applicant understood that a “guided wave” technology may be able to provide some qualitative information on whether the embedded shell has undergone corrosion; however, neither this nor any other known non-destructive methods could determine the thickness of the embedded drywell shell or the specific extent of corrosion.

Based on review of the applicant’s evaluation of the condition of the inaccessible portion of drywell shell embedded in concrete, the applicant’s actions to date to minimize entry of water in the concrete-to-shell interface, and the enhanced inspection program including a detailed UT measurement plan of the embedded shell area committed by the applicant, the staff concludes with reasonable assurance that the environment in the region is sufficiently non-aggressive for no significant progressive corrosion. Therefore, the staff concern is resolved and Open Item 4.7.2-1.2 is closed.

In its letter dated February 15, 2007, the applicant change a commitment (Commitment No. 27) by adding Item 20, which states AmerGen is committed to perform visual and UT inspections of the drywell shell in the inspection trenches in drywell bays #5 and #17. AmerGen will monitor the two trenches for the presence of water during each refueling outage. The staff identified this commitment item as a license condition.

<u>Ultrasonic Testing Measurement Issues</u>

In the sand pocket region of the drywell shell, the most susceptible bays are incorporated in the sampling. However, the staff believes that readings should be taken at vulnerable locations and that UT techniques are reliable. The first issue is addressed as part of Open Item 4.7.2-1.2 and the second issue is addressed below.

The second item is that a review of UT data indicates that the UT measurements taken from inside the drywell after 1992 show a general increase in the metal thickness. In some cases, the average increase is as much as 40 mils in a 2-year timeframe. In general, it appears that the UT measurements taken after 1992 require proper calibration, considering the coatings on both sides of the drywell shell. The staff requested that the applicant address this issue during a public meeting held June 1, 2006.

In its response dated June 20, 2006, the applicant provided the following discussion of sensitivities involved with the UT measurement process and how they will be minimized in the future:

> UT Instrumentation Uncertainties. The UT instrumentation, which includes the transducer, cable and ultrasonic unit, will be calibrated to within approximately +/- 0.010 inches. Exelon Procedure (ER-AA-335-004) step 4.1.3 requires that he UT instruments must be checked within 2% of the calibration standard (block) prior to use. For the sand bed region, which is nominally 1" thick, a 1-inch thick calibration standard block is used. This results in checking the UT instrument to within 0.020" inches or +/- 0.010". UT instrumentation accuracy is verified under controlled conditions where UT thickness readings are performed on calibration blocks. The calibration blocks have been precisely machined to prescribed thicknesses, which are then verified by micrometer readings.
>
> Actual Drywell Surface Roughness and UT Probe Location Repeatability. Due to the corrosion, the outside surface of the Drywell Vessel is not smooth and uniform. The surface condition is indicative of general corrosion, which is rough with high and low points spaced very closely together. This profile was verified when the sand was removed in 1992. The UT Instrumentation probes are 7/16" in diameter and are dual element transducers (i.e. half transmits sound and the other half receives). The probes emit a focused beam that measures an area significantly smaller than 7/16" diameter and will record the thinnest reading within that area.
>
> Because the surface roughness of the drywell within this 7/16" diameter can vary, the probe must be placed at precisely the same location to precisely repeat a thickness reading. A slight shift of the probe will result in a reading which is correct, but different from a previous reading.
>
> The variability associated with this factor is reduced by the use of the stainless steel template. The template has been manufactured with holes in a 7 by 7 pattern on 1 inch centers. Each of the 49 holes has been machined with a diameter so that the UT probe fits within each hole snugly. The templates are machined with 1/16" wide slits on each edge of the template at 0, 90, 180, and 270 degrees. During inspections the slits in the template are lined up with permanent marks that were placed on the drywell shell when the location was originally inspected. The UT readings are then taken by placing the probe inside each hole in the template.
>
> Inspection procedures require that NDE personnel performing the inspection place the template precisely on the permanent markings.

Actual Drywell Surface Roughness and UT Probe Rotation. The UT probe sends the signal from one side of the probe and receives the signal on the other side. The probe must be oriented in the same plane in order to measure exactly the same point. Test data taken on a mock up with similar roughness showed that a variance up to 0.016 inch was noted when rotating the probe 360 degrees over the same spot. Therefore, a slight rotation of the probe will result in a reading, which is correct, but different from a previous reading.

Inspection procedures require that NDE personnel performing the inspection place the probe in the same orientation.

Temperature Effects. Significant temperature differences between inspections may result in a shift in the material thickness. Therefore, the inspection specification will require that NDE personnel performing the inspection record the surface temperature of the area that is inspected.

Batteries. Inspection specifications require the installation of new batteries prior to each series of inspections.

NDE Technician. Inspection specifications require that personnel conducting UT examinations be qualified in accordance with Exelon Procedure ER-AA-335-004.

Calibration Block. Exelon Procedure ER-AA-335-004 requires that calibration blocks used during the inspection be inspected to verify that the ultrasonic response equals the physical measurement.

Internal Surface Cleanliness. The inspection areas are covered with a qualified grease to protect the examination surface from rusting between inspection periods. The grease must be removed prior to the inspection and reapplied after the inspection. Tests performed in April and May of 2006 show that the presence of the grease will increase the readings as much as 12 mils. In 1996, the governing specification did not clearly specify the requirement to remove the grease prior to the inspection. Therefore it is possible that the requirement to remove the grease was not communicated to the contractor, and that the contractor who performed the 1996 inspection may have not removed the grease.

The inspection procedures will clearly require that personnel conducting UT examinations remove the grease prior to performing the examination.

UT Unit Settings. It is possible that the ultrasonic unit can be set in a "high gain" setting which may bias the machine into including the external coating as part of the thickness. Future inspections will use modern "state of the art" UT units that do not have gain

settings.

Identification of the Physical Inspection Location. There is a potential that inspection locations may be mislabeled on the data sheets. The inspection procedures uniquely and clearly identify each inspection location and provide the specific instruction as to the area's location.

Data Analysis. The above potential variables will be considered in the analysis of the data. The analysis not only determines a mean for each grid or sub-grid, but also the variance of the means. These variances will be compared to past inspections to ensure consistency. The mean and the variance are compared to the acceptance criteria.

> In addition, the mean UT thickness values for a current inspection will be computed and compared to the previous inspection prior to restarting from an outage. If data anomalies similar to 1996 are identified corrective actions will be taken, including new UT measurements, as necessary, to ensure accuracy of measurements.

Based on the applicant's discussion of the variables involved in the UT results, the staff finds it reasonable to conclude that the anomalous readings of 1994 and 1996 could be attributed to one or more of the factors enumerated in the discussion. The staff was concerned about systematic corrections to the UT measurements and could not determine the basis for the applicant's use of the anomalous readings nor systematic corrections. The applicant could not isolate the factors that contributed to these anomalous results; therefore, it plans to utilize the lessons learned from the experience for the future UT examinations. On the basis of the applicant's written response, the staff determined that its concerns have been resolved.

4.7.2.2.2 Minimum Drywell Thickness

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide a summary of the factors considered in establishing the minimum required drywell thickness.

In its response dated April 7, 2006, the applicant explained that the factors considered in establishing the minimum required drywell thickness at various elevations of the drywell are described in detail in engineering analyses documented in two GE reports, Index Nos. 9-1, 9-2, and 9-3, 9-4. Report Index No. 9-1, 9-2 was generated for the drywell condition with sand in the sand bed region and Report Index No. 9-3, 9-4 addressed the drywell condition without sand in the sand bed region. The two reports were transmitted to the staff in December 1990 and 1991, respectively. Report Index No. 9-3, 9-4 was revised later to correct errors identified during an internal audit and was resubmitted to the staff in January 1992. The analysis described in Report Index No. 9-3, 9-4 (i.e., without sand) is the current applicable analysis for the drywell.

In its response the applicant also noted that it based the analysis on the original code of record, ASME Code, Section VIII, and Code Cases 1270N-5, 1271-N, and 1272N-5. The ASME Code and its Code Cases do not provide specific guidance in two areas. The first relates to the size of a region of increased membrane stress due to thickness reductions from local or general corrosion effects, and the second pertains to the allowable stresses for Service Level C or post-accident conditions. In the first case, guidance was sought from ASME Code Section III, NE-3213.10. For Service Level C or post-accident conditions, the SRP-LR was used as guidance to develop the allowable stresses. Additionally, the applicant summarized the analysis efforts in the following paragraphs:

> The analysis is based on a 36-degree section model that takes advantage of symmetry of the drywell with 10 vents. The model includes the drywell shell from the base of the sand bed region to the top of elliptical head and the vent and vent header. The torus is not included in this model because the vent bellows provide a very flexible connection, which does not allow significant structural interaction between the drywell and the torus. The analysis considered drywell geometry and materials, thickness reduction from corrosion, test loads, normal operating loads,

design basis accident loads, seismic loads, refueling loads, and design basis load combinations. Pressure and temperature were in accordance with approved Technical Specification Amendment No. 165, which established a revised design bases accident pressure of 44 psig and accident temperature of 292°F. The results of the analysis show that the minimum required ASME Code thickness of the drywell shell above the sand bed region is controlled by membrane stresses and the minimum drywell shell thickness in the sand bed region is controlled by buckling. The minimum required ASME Code thicknesses above the sand bed region are shown in Table 1 (attached to the response). For the sand bed region, the analysis conservatively assumed that the shell thickness in the entire sand bed region has been reduced uniformly to a thickness of 0.736 inches. This thickness satisfies ASME Code requirements and is considered the minimum required thickness.

As described above, the buckling analysis was performed, assuming a uniform general thickness of the sand bed region of 0.736 inches. However, the UT measurements identified isolated, localized areas where the drywell shell thickness is less than 0.736 inches. Acceptance for these areas was based on engineering calculation C-1 302-1 87-5320-024. The calculation uses a “Local Wall Acceptance Criteria.” This criterion can be applied to small areas (less than 12" by 12"), which are less than 0.736" thick so long as the small 12" by 12" area is at least 0.536" thick. However, the calculation does not provide additional criteria as to the acceptable distance between multiple small areas. For example, the minimum required linear distances between a 12" by 12" area thinner than 0.736" but thicker than 0.536", and another 12" by 12" area thinner than 0.736" but thicker than 0.536", were not provided.

The actual data for two bays (13 and 1) shows that there is more than one 12" by 12" area thinner than 0.736" but thicker than 0.536". Also the actual data for two bays shows that there is more than one 2½ in. diameter area thinner than 0.736" but thicker than 0.490". Acceptance is based on the following evaluation. The effect of these very localized wall thickness areas on the buckling of the shell requires some discussion of the buckling mechanism in a shell of revolution under an applied axial and lateral pressure load.

To begin the discussion, we will describe the buckling of a simply supported cylindrical shell under the influence of lateral pressure and axial load. As described in chapter 11 of the Theory of Elastic Stability, Second Edition, by Timoshenko and Gere, thin cylindrical shells buckle in lobes in both the axial and circumferential directions. These lobes are defined as half wave lengths of sinusoidal functions. The functions are governed by the radius, thickness and length of the cylinder. If we look at a specific thin walled cylindrical shell, both the

length and radius would be essentially constants and if the thickness was changed locally, the change would have to be significant and continuous over a majority of the lobe so that the compressive stress in the lobe would exceed the critical buckling stress under the applied loads, thereby causing the shell to buckle locally. This approach can be easily extrapolated to any shell of revolution that would experience both an axial load and lateral pressure as in the case of the drywell. This local lobe buckling is demonstrated in the GE Letter Report "Sandbed Local Thinning and Raising the Fixity Height Analysis” where a 12 x 12 square inch section of the drywell sand bed region is reduced by 200 mils and a local buckle occurred in the finite element eigenvalue extraction analysis of the drywell. Therefore, to influence the buckling of a shell, the very local areas of reduced thickness would have to be contiguous and of the same thickness. This is also consistent with Code Case 284 in Section-1700 which indicates 'that the average stress values in the shell should be used for calculating the buckling stress. Therefore, an acceptable distance between areas of reduced thickness is not required for an acceptable buckling analysis except that the area of reduced thickness is small enough not to influence a buckling lobe of the shell. The very local areas of thickness are dispersed over a wide area with varying thickness and as such will have a negligible effect on the buckling response of the drywell. In addition, these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffening effect limits the shell buckling to a point in the shell sand bed region which is located at the midpoint between two vents.

The acceptance criteria for the thickness of 0.49 inches confined to an area less than 2½ inches in diameter experiencing primary membrane + bending stresses is based on ASME Boiler and Pressure Vessel (B&PV) Code, Section III, Subsection NE, Class MC Components, Paragraphs NE-3213.2 Gross Structural Discontinuity, NE-3213.10 Local Primary Membrane Stress, NE-3332.1 Openings not Requiring Reinforcement, NE-3332.2 Required Area of Reinforcement and NE-3335.1 Reinforcement-of Multiple Openings. The use of Paragraph NE-3332.1 is limited by the requirements of Paragraphs NE-3213.2 and NE-3213.10. In particular, NE-3213.10 limits the meridional distance between openings without reinforcement to 2.5 x (square root of Rt). Also, Paragraph NE-3335.1 only applies to openings in shells that are closer than two times their average diameter. The implications of these paragraphs are that shell failures at these locations from primary stresses produced by pressure cannot occur provided openings in shells have sufficient reinforcement. The current design pressure of 44 psig for the drywell requires a thickness of 0.479 inches in the sand bed region of the drywell. A review of all the UT data presented in Appendix D of the calculation indicates that all thicknesses in the drywell sand bed region exceed the required pressure thickness by a substantial margin. Therefore, the requirements for pressure reinforcement specified in the previous paragraph are not required for the very local wall thickness evaluation presented in Revision 0 of Calculation C-1302-187-5320-024.

Reviewing the stability analyses provided in both the GE Report 9-4 and the GE Letter Report, “Sand bed Local Thinning and Raising the Fixity Height Analysis,” and recognizing that the plate elements in the sand bed region of the model are 3" x 3", it is clear that the circumferential buckling lobes for the drywell are substantially larger than the 2½ inch diameter very local wall areas. This, combined with the local reinforcement surrounding these local areas, indicates that these areas will have no impact on the buckling margins in the shell. It is also clear from the GE Letter Report that a uniform reduction in thickness of 27 percent to 0.536" over a one square foot area would only create a 9.5 percent reduction in the load factor and theoretical buckling stress for the whole drywell resulting in the largest reduction possible. In addition to the reported result for the 27 percent reduction in wall thickness, a second buckling analysis was performed for a wall thickness reduction of 13.5 percent over a one square foot area which only reduced the load factor and theoretical buckling stress by 3.5 percent for the whole drywell, resulting in the largest reduction possible. To bring these results into perspective, a review of the nondestructive examination (NDE) reports indicates that there are 20 UT measured areas in the whole sand bed region that have thicknesses less than the 0.736 inch used in GE Report 9-4, which cover a conservative total area of 0.68 square feet of the drywell surface with an average thickness of 0.703" or a 4.5 percent reduction in wall thickness.

Therefore, to effectively change the buckling margins on the drywell shell in the sand bed region a reduced thickness would have to cover approximately one square foot of shell area at a location in the shell that is most susceptible to buckling with a reduction in thickness greater than 25 percent. This leads to the conclusion that the buckling of the shell is unaffected by the distance between the very local wall thicknesses, in fact these local areas could be contiguous provided their total area did not exceed one square foot and their average thickness was greater than the thickness analyzed in the GE Letter Report, and provided the methodology of Code Case N284 was employed to determine the allowable buckling load for the drywell. Furthermore, all of these very local wall areas are centered about the vents, which significantly stiffen the shell. This stiffening effect limits the shell buckling to a point in the shell sand bed region, which is located at the midpoint between two vents.

In summary, the applicant noted that the minimum required drywell shell thickness is based on an analysis conducted in accordance with ASME Code. Factors considered include drywell geometry, material of construction, reduced wall thickness due to corrosion, and applicable design-basis loads and load combinations. Accident pressure and temperature are 44 psig and 292 °F, respectively, in accordance with the approved technical specification amendment No. 165.

In a letter dated April 7, 2006, the applicant responded to RAI 4.7.2-1. In its response the applicant stated that the minimum required thicknesses of the drywell shell above the sand bed region shown in Table-1 of the response are controlled by membrane stresses. The minimum required general drywell shell thickness in the sand bed region of 0.736 inch is controlled by buckling. Localized areas in the sand bed region where the thickness is less than 0.736 inch are evaluated against a local thickness acceptance criteria (0.49 inch) developed based on ASME Code, Section III, Subsection NE, Class MC Components, Paragraphs NE-3213.2, “Gross Structural Discontinuity,” NE-3213.10, “Local Primary Membrane Stress,” NE-3332.1, “Openings Not Requiring Reinforcement,” NE-3332.2, “Required Area of Reinforcement,” and NE-3335.1, “Reinforcement of Multiple Openings.” Application of these ASME Code sections is justified as discussed above, and specific buckling sensitivity analysis results support the conclusion that, on an average wall thickness basis, buckling of the shell is unaffected by local wall thickness

areas as these are distributed over the sand bed region.

The staff reviewed the cited analysis reports to ensure that the parameters used and the assumptions made in the analysis are valid for the period of extended operation. However, based on the review conducted, the staff requested that the applicant provide additional information to address certain gross assumptions.

Attachment 1A of the GPU letter dated November 26, 1990, makes a statistical evaluation of the UT measurement data taken up to 1990. On the cover page of the report, GPU Nuclear

Corporation states a disclaimer, “the work is conducted by an individual(s) for use by GPU. Neither GPU nor the authors of the report warrant that the report is complete of accurate ….” In view of this disclaimer, the staff at a public meeting on June 1, 2006, asked the applicant to provide a detailed description of the way the UT measurement data, whether taken as part of the 6-inch by 6-inch grid, or isolated readings, were evaluated and used in performing the analysis.

In its response dated June 20, 2006, the applicant clarified the use of the statistical evaluation as follows:

> The disclaimer noted by the NRC staff is on the cover page of Technical Data Report (TDR) No. 948 Revision 1, "Statistical Analysis of the Drywell Thickness Data.” The disclaimer statement is a standard clause that was placed on TDRs developed in accordance with the applicable GPUN procedure at the time. AmerGen points out that TDR No. 1027, which is also a part of Attachment 1A includes the same disclaimer. The disclaimer was intended to reinforce that TDRs are not design basis documents and were not design verified in accordance with the GPUN QA Program. In this case TDR 948 was developed to summarize the initiative that surveyed the drywell and that assessed initial corrosion rates based on data collected from 1986 through December 1988. However this TDR did not serve as the design basis document, which demonstrated the drywell shell met design basis requirements. The TDR in Section 1 (Introduction/Background) explains that the TDR documents the assumptions, methods and results of the statistical analysis used to evaluate the corrosion rates. The section then states that the complete analysis is documented in calculation C-1302-187-5300-005.
>
> Calculation C-1302-187-5300-005, "Statistical Analysis of Drywell Thickness Data Thru 12-31-88" did serve as the design basis document, which demonstrated the drywell shell met design basis requirements. This calculation was developed and design verified in accordance with the GPUN QA Program and is approximately 200 pages long. A review of the information contained in the TDR Section 4.6 (Summary of Conclusion) shows that it is consistent with the information in Section 2 (Summary of Results) in calculation C-1302-0187-5300-005. Thus, the information in the TDR No. 948 represents design quality information.
>
> In response to the NRC's question on how the UT measurement data were evaluated and used in the drywell analysis, AmerGen provided a description of how the 49-point array statistical analysis was performed in response to NRC Q&A #AMP-356, item (4). In that response, AmerGen stated that the methodology and acceptance criteria that are applied to each grid of point thickness readings, including both global (entire array) evaluation and local (subregion of array) are described in engineering specification IS-328227-004 and in calculation No. C-1302-187-5300-011, "Statistical Analysis of Drywell Thickness Data Thru 4-24-90". This calculation is the more recent version of calculation C-1302-187-5300 and has been submitted by AmerGen to the NRC.
>
> These two documents were submitted to the NRC in a letter dated November 26, 1990 and provided to the Staff during the AMP/AMR audit. A brief summary of the methodology and acceptance criteria is described below.

The initial locations identified in 1986 and 1987 where corrosion loss was most severe were selected for repeat inspection over time to measure corrosion rates. For locations where the initial investigations found significant wall thinning, UT inspection consisted of 49 individual UT data points equally spaced over a 6"x 6" area. Each new set of 49 values was then tested for normal distribution. If the data was normally distributed, then the mean value of the 49 points was calculated and used to represent the general drywell shell thickness in the tested area. If the 49 points were not normally distributed, then the grid was subdivided into datasets (usually 2, top and bottom) that were normally distributed. The mean value for each dataset was then calculated. The minimum mean value was compared to the minimum required thickness as described below.

The mean values of each grid were then compared to the required minimum uniform thickness criteria of 0.736 inches. In addition each individual reading was compared to the local minimum required criteria of 0.490 inches. The basis for the required minimum uniform thickness criteria and the local minimum required criteria is provided in response to NRC Question #AMP-210. A decrease in the mean value over time is representative of corrosion. If corrosion does not exist, the mean value will not vary with time, although random variations in the UT measurements as a result of such factors as variables in the inspection process and in environmental conditions may occur. If corrosion is continuing, the mean thickness will decrease linearly with time. Therefore the curve fit of the data is tested to determine if linear regression is appropriate, in which case the corrosion rate is equal to the slope of the line. If a slope exists, then upper and lower 95% confidence intervals of the curve fit are calculated. The lower 95% confidence interval is then projected into the future and compared to the required minimum uniform thickness criteria of 0.736 inches.

A process similar to that described above is applied to the thinnest individual reading in each grid. The lowest reading taken is also verified against the local minimum thickness requirement. Then the curve fit of the data is tested to determine if linear regression is appropriate. If a slope exists, then the lower 95% confidence interval is then projected into the future and compared to the required minimum local thickness criteria of 0.490 inches.

The staff finds that the applicant has provided an explanation of the documents used for the design basis calculations. Furthermore, the applicant provided the process used in establishing the minimum thickness of the drywell used in the 1991 GE analysis. Based on the discussion provided above, the staff finds the applicant's historical method of determining the minimum required wall thickness acceptable because these processes use recognized industry standards for performance and evaluation of results. On the basis of the applicant's written response, the staff determined that its concerns related to the disclaimer in the Technical Data Report had been resolved.

Open Item 4.7.2-1.3: ASME Code Case N-284

In the applicant's discussion, a summary of the methods and assumptions used in the buckling analysis of the shell in the sand-pocket area has been given. Though it has not endorsed ASME Code Case N-284 for use, the staff does not take exception to the use of average compressive stress across the metal thickness for buckling analysis of the as-built shell. However, if the corrosion has reduced the strength of the remaining metal through the cross section, this assumption may not be valid. The staff requests the applicant to address this issue.

In its response dated June 20, 2006, the applicant provided the following discussion on the use of ASME Code Case N-284:

> Although Revision 1 of Code Case 284 had not yet been issued when the Reference 2 report (An ASME Section VIII Evaluation of Oyster Creek Drywell for Without Sand Case, Part II – Stability Analysis," GE Report, Index No. 9-4, Revision 0, DRF # 00664) was written, the authors had the benefit of consultation with Dr. Clarence Miller who was the primary author of the revision. Thus, the plasticity correction factors used in the evaluation (in Figure 2-4 of Reference 2) are the same as those in Figure 1610-1 of Code Case N-284 Revision 1.
>
> Paragraph 1500 in both revisions allows higher values of capacity reduction factors due to internal pressure by stating, "The influence of internal pressure on a shell structure may reduce the initial imperfections and therefore higher values of capacity reduction factors α_{ij} may be acceptable. Justification for higher values of α_{ij} must be given in the design report." The technical approach documented and used in the Reference 2 analysis was reviewed and accepted by Dr. Miller in Reference 4 (Miller, C.D., 1991, "Evaluation of Stability Analysis Methods Used for the Oyster Creek Drywell," Docket No. 50-219, September 12, 1991, CBI Technical Services Company Report prepared for GPU Nuclear Corporation). that is also cited as one of the references in Reference 3 report (NUREG/CR-6706 "Capacity of Steel and Concrete Containment Vessels With Corrosion Damage,"February 2001").
>
> Thus, the technical approach used in the stability evaluation of Reference 2 is entirely consistent with the guidelines in Revision 1 of Code Case N-284.
>
> In the Reference 6 report (Miller, C.D., "Applicability of ASME Code Case N-284-1 to Buckling Analysis of Drywell Shell," June 15, 2006), Dr. Miller discussed the applicability of the N-284-1 methods to corroded shells. He indicated that the imperfection limit indicated by a parameter e/t (where ‘e' is the eccentricity and ‘t' is the shell thickness) was assumed as 1.0 in Code Case N-284-1. The imperfections could be from the fabrication process in the case of a new shell or could be from a combination of fabrication and corrosion in the shells already in service. The contribution to e/t parameter from corrosion was defined as follows:
>
> $$(e/t)_{corrosion} = (t_n - t_c)/(2t_c)$$
>
> For the sand bed region, if we assume the minimum general corroded thickness of 0.736 inch and the nominal thickness of 1.154 inches, the $(e/t)_{corrosion}$ works out to be (1.154-0.736)/(2x0.736) or 0.28. However, this does not mean the preceding value of $(e/t)_{corrosion}$ need always be added to the (e/t) value from fabrication. In fact it needs to be subtracted where the fabrication related eccentricity is in the outward radial direction. Since the fabrication related eccentricities are likely randomly distributed and thus are equally like in either direction, the overall net effect of the corrosion-induced eccentricities would be insignificant. Thus, it is concluded that the corrosion on the outside surface of the shell will not introduce

> eccentricities that would significantly impact the e/t value of 1.0 assumed in Code Case N-284.

As a summary, the applicant stated:

> The stress analysis of Oyster Creek drywell satisfies the local primary stress requirements of NE-3213.10. Conservatism in the allowable primary stress intensity value, the assumed peak pressure during the LOCA condition and the assumption of local corroded thickness in the entire region of the drywell provide additional structural margin.
>
> Since the Code primary stress limits are satisfied in the corroded condition and the number of fatigue cycles is small, the surface discontinuities from corrosion do not represent a significant structural integrity concern.
>
> The technical approach used in the stability evaluation of the Oyster Creek drywell is consistent with the requirements specified in Code Case N-284, Revision 1. Additional eccentricity produced by shell corrosion in service is expected to be accommodated within the allowable limit for imperfections.
>
> As indicated in Table-1, UT measurements of the drywell shell above the sand bed region show that the measured general thickness contains significant margin. Considering the ongoing corrosion in that region is insignificant, the margin can be applied to offset uncertainties related to surface roughness.
>
> UT measurements of the drywell shell in the sand bed region show that the measured general thickness is greater than the 0.736 inch thickness assumed in the buckling analysis by significant margin except in 2 bays, bay #17 and bay #19. (Refer to response to RAI 4.7.2-1(d), Table-2). The margin in the general thickness of the two bays is 0.074 inch and 0.064 inch respectively. Considering that significant additional corrosion is not expected in the sand bed region, the margin can be applied to offset uncertainties related to the surface roughness.

The staff finds that the applicant has provided a thorough explanation of the factors considered in applying the ASME Code Case N-284-1 for buckling analysis of the corroded shell in the sand bed area of the drywell shell. However, it does not address the staff's concern about whether it is appropriate to assume the same strength across the corroded section of the shell. The incorporation of the “e/t” corrosion concept to arrive at a representative distribution of strength along the corroded section that recognizes the lower strength at the corroded side and full strength at the inside surface could support the claim of conservatism in the analysis. This was

identified as OI 4.7.2-1.3 in the SER, dated August 18, 2006.

On further evaluation of the applicant’s information, the staff concludes that the stability evaluation was consistent with the guidelines of ASME Code Case N-284-1. The staff’s concern about use of the same section strength across the corroded section of the shell is addressed by the Code Case N-284-1, which uses conservative assumptions to determine shell capacity reduction factors (*i.e.*, assumption of imperfection limit indicated by parameter “e/t” to be 1.0 in the code case) expected to compensate reasonably for such use of same section strength. In addition, the applicant conservatively assumed the local corroded thickness for the entire drywell shell region and demonstrated that the code allowable stresses were satisfied consistently with the guidelines of the code case. Thus, this analysis adds a margin of safety for the drywell stability evaluation. On this basis, the staff believes that the stability evaluation method is adequate and acceptable, and the staff's concern is resolved. Open Item 4.7.2-1.3 is closed.

Open Item 4.7.2-1.4: Localized Thin Areas

For the localized thin areas, the applicant is using the provision of NE-3213.10 of Subsection NE of Section III of the ASME Code. This provision, although not directly applicable to the randomly thin areas caused by corrosion, if used with care and adequate conservatism, may provide some idea about the primary stress levels at the junction of the thin and thick areas. The staff requested that the applicant provide a summary of the process used to address this issue.

In its response dated June 20, 2006, the applicant noted that this is the only method available and that this approach was accepted by the staff in the 1990s. Recently, the applicant had contracted GE to review the 1991 analysis for the purpose of identifying conservatism. The applicant summarized the GE report as follows:

> Although the ASME Section III and Section VIII analysis procedures were not developed for randomly thin areas caused by corrosion, GE has concluded that the same analysis procedures are applicable to in-service components as long as the section thickness values used are adjusted to account for the reduction due to corrosion. Table 2-1 of Reference 1 lists the nominal thickness values and the 95% confidence level thickness values in the locally corroded areas. Even though the corroded thickness is present only in a very local area of a region, the reduced value was used for that drywell region in the Section VIII stress analysis.
>
> ASME Section III, Subsection NE-3213.10 states that membrane stress produced by pressure or other mechanical loading and associated with a primary or discontinuity effect produces excessive distortion in the transfer of load to other portions of the structure. Conservatism requires that such stress be classified as a local primary membrane stress even though it has some characteristics of a secondary stress. A stressed region may be considered local if the distance over which the membrane exceeds 1.1 S_{mc} (stress intensity) does not extend in the meridional direction more than 1.0(Rt)½, where S_{mc} is as defined in Subsection NE-3112.4, R is the minimum mid surface radius of curvature and t is the minimum thickness in the region considered. Regions of local primary stress intensity involving axisymmetric membrane distributions which exceed 1.1S_{mc} shall not be closer in the meridional direction than 2.5 (Rt)½, where R is defined as (R1 + R2)/2 and t is defined as (t1 + t2)/2, where t1 and t2 are the minimum thicknesses at each of the regions considered and R1 and R2 are the minimum midsurface radii of curvature at these regions where the membrane stress intensity exceeds 1.1 S_{mc}. The requirements of ASME Section III, Subsection NE-3213.10 were satisfied by determining the maximum meridional extent of the areas where the local primary membrane stress exceeds 1.1 S_{mc}, but is below the allowable value of 1.5 S_{mc} [Reference 1]. The maximum extent was determined to be 11 inches (using the large displacement solution) and was found to be acceptable [i.e., less than the allowable value of 1.0(Rt)½ or 17.6 inches]. Given that a uniform minimum corroded thickness for a drywell region is used in the evaluation, the preceding analysis is expected to be bounding for the actual corroded condition.
>
> The applicant notes that the above evaluation was based on a peak internal pressure of 62 psi. However, the applicant points out that the Oyster Creek

specific calculation with an adder of 15% showed the peak internal pressure as 44 psi, and that this value was approved by the NRC in 1993.

The applicant noted that "although provisions in ASME Code Section III, Subsection NE-3213.10 are not directly applicable to the randomly thin areas caused by corrosion, AmerGen believes that the provisions are applicable to the analysis of Oyster Creek drywell shell based on the following:

- The stress analysis of Oyster Creek drywell presented in Reference 1 satisfies the local primary stress requirements of NE-3213.10. Conservatism in the allowable primary stress intensity value, the assumed peak pressure during the LOCA condition and the assumption of local corroded thickness in the entire region of the drywell provide additional structural margin.

- The Code primary stress limits are satisfied in the corroded condition and the number of fatigue cycles is small, the surface discontinuities from corrosion do not represent a significant structural integrity concern.

- As indicated in Table-1, UT measurements of the drywell shell above the sand bed region show that the measured general thickness contains significant margin. Considering the ongoing corrosion in that region is insignificant, the margin can be applied to offset uncertainties related to surface roughness.

Table 4.7.2 Drywell Shell Thickness and the Minimum Available Thickness Margin

Drywell Region	Nominal Design Thickness (inches)	Minimum Measured Thickness, (inches)	Minimum Required Thickness (inches)	Minimum Available Thickness Margin (inches)
Cylindrical	0.640	0.604	0.452	0.152
Knuckle	2.625	2.54	2.29	0.25
Upper Sphere	0.722	0.676	0.518	0.158
Middle Sphere	0.770	0.682	0.541	0.141
Lower Sphere[1]	1.154	0.800[1]	0.629	0.171
Sand Bed [2]	1.154	0.800	0.736	0.064

1. The general thickness in the lower sphere is conservatively assumed to be the same as the sand bed region.
2. The minimum required general thickness in the sand bed region is controlled by buckling analysis, governed by load combinations that do not include the 44 psi pressure.

- UT measurements of the drywell shell in the sand bed region show that the measured general thickness is greater than the 0.736'" thickness assumed in the buckling analysis by significant margin except in 2 bays, bay 17 and bay 19. (Refer to response to RAI 4.7.2-1(d), Table-2). The margin in the general thickness of the two bays is 0.074" and 0.064" respectively. Considering that significant additional corrosion is not expected in the sand bed region, the margin can be applied to offset uncertainties related to the surface roughness.

The staff identified this issue as OI 4.7.2-1.4 in the SER, dated August 18, 2006.

After further evaluation of the applicant's justification, the staff concludes that use of the NE-3213.10 provisions of Subsection NE of Section III of the ASME Code is acceptable. The staff's acceptance is based on the applicant's conservative approaches to its determination of the allowable shell capacity. Specifically, the applicant demonstrated acceptable shell capacity based on use of a conservative LOCA peak internal pressure (i.e., peak internal pressure of 62 psi in the evaluation versus the 44 psi peak internal pressure in an Oyster Creek specific calculation approved by the NRC in 1993), use of local corroded thickness for the entire region of the drywell, and compliance with local primary stress code limits in the corroded condition. In addition, the applicant expects its enhanced actions to prevent additional corrosion in the sand bed region. On this basis, the staff's concern is resolved and Open Item 4.7.2-1.4 is closed.

4.7.2.2.3 Mitigating Actions

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide a summary of the actual mitigating actions taken and their effectiveness.

In its response dated April 7, 2006, the applicant listed the following actions:

- cleared the former sand bed region drains to improve drainage,
- replaced reactor cavity steel trough drain gasket, which was found to be leaking,
- removed water from the sand bed region,
- installed a cathodic protection system in bays with greatest wall thinning in early 1989 - subsequent UT thickness measurements in these bays showed that the system was not effective in reducing the rate of corrosion and was removed from service in 1992,
- removed sand in the sand bed region to break up the galvanic cell,
- removed corrosion products from the external side of the shell in the sand bed region,
- upon sand removal, the sand bed concrete floor was found cratered and unfinished - the concrete floor was repaired, finished and coated to permit proper drainage of the sand bed region,
- applied a silicone seal at the juncture of the drywell shell and the sand bed concrete floor to prevent intrusion of moisture into the embedded drywell shell in concrete,
- applied a multi-layered epoxy protective coating to the exterior surfaces of the drywell shell in the sand bed region (i.e., one pre-primer coat, and two top coats),
- applied stainless steel type tape and strippable coating to the reactor cavity during refueling outages to seal identified cracks in the stainless steel liner, this limits water intrusion into the gap between the drywell shell and the drywell shield wall, and confirmed that the reactor cavity concrete trough drains are not clogged

The applicant further explained that these mitigating features have been in place since 1992. The most effective feature was the removal of sand in the sand bed region to break up the galvanic cell, which significantly reduced the rate of corrosion in that region. The sand bed region coating is effective because it is protecting the underlying drywell shell from ongoing corrosion, as confirmed by a comparison of UT measurements taken in 1992, 1994, and 1996. The other features, except for cathodic protection, are also effective because their implementation limited water intrusion into the gap between the drywell shell and the drywell shield wall, thus reducing the rate of corrosion in the upper region of the drywell.

A comparison of UT measurements taken in 1992, 1994,1996, 2000, and 2004 on the upper region of the drywell shell shows that either the corrosion is no longer occurring or is negligible considering the accuracy of UT instruments. As stated previously, the cathodic protection system was installed in the bays with the greatest wall thinning in early 1989. Subsequent UT thickness measurements in these bays showed that the system was not effective in reducing the rate of corrosion and was removed from service in 1992.

Based on the discussion above, the staff finds the applicant's response to item (c) acceptable, as it describes the mitigating actions taken by the applicant. The staff's concern described in RAI 4.7.2-1(c) is resolved.

4.7.2.2.4 Chart of Ultrasonic Test Measurements

In RAI 4.7.2-1 dated March 10, 2006, the staff requested that the applicant provide a comparative graph (or chart) showing the drywell thickness based on the assumed corrosion rate and that actually found after the mitigating actions were implemented.

In its response dated April 7, 2006, the applicant provided Tables 1 and 2. These tables provide UT thickness measurements for the upper region of the drywell, and for the sand bed region of the drywell shell, respectively.

The staff finds the tables and figures useful in understanding the extent of corrosion. The staff's concern described in RAI 4.7.2-1(d) is resolved.

4.7.2.2.5 Location of Drywell Corrosion

Junction of Drywell Floor and Shell

In RAI 4.7.2-2 dated March 10, 2006, the staff noted that a number of Mark I containments have experienced corrosion inside their drywells at the junction of the bottom concrete floor and the steel shell. The staff requested that the applicant provide information regarding corrosion of the drywell shell at this location or any other location of the drywell inside surfaces.

In its response dated April 16, 2006, the applicant stated that OCGS has not experienced corrosion on the inside surfaces of the drywell shell, including the junction of the bottom concrete floor and the steel shell. The inside of the drywell is coated with Carbo-Zink 11 over an SSPC-SP6/SP5, commercial abrasive blast surface preparation to a dry film thickness of 3-6 mils. Moreover, visual inspections conducted in accordance with ASME Code Section XI, Subsection IWE, have not identified recordable corrosion at the junction of the bottom concrete floor and the steel shell or any other location inside the drywell. Minor surface rust has been noted in some areas where the coating is damaged or removed for UT measurements. The minor surface rust is limited to isolated areas and does not impact the intended function of the drywell.

Based on the above discussion, the staff finds this response acceptable, as the condition would not challenge the intended function of the drywell shell. The staff's concern described in RAI 4.7.2-2 is resolved.

<u>Open Item 4.7.2-3: Leakage From Refueling Seal</u>

In RAI 4.7.2-3 dated March 10, 2006, the staff noted that leakage from the refueling seal has been identified as one of the reasons for accumulation of water and contamination of the sand-pocket area. The refueling water passes through the gap between the shield concrete and the drywell shell in the long length of inaccessible areas. As there is a potential for corrosion in this area, ASME Code Subsection IWE would require augmented inspection of this area. The staff requested that the applicant provide a summary of inspections performed (visual and nondestructive examination (NDE)) and mitigating actions taken to prevent water leaks from the refueling seal components.

In its response dated April 16, 2006, the applicant stated that the refueling seals at OCGS consist of stainless steel bellows. In the mid-to-late 1980s, GPU conducted extensive visual and NDE inspections to determine the source of water intrusion into the seismic gap between the drywell concrete shield wall and the drywell shell and its accumulation in the sand bed region. The inspections concluded that the refueling bellows (seals) were not the source of water leakage. The bellows were repeatedly tested using helium (external) and air (internal) without any indication of leakage. Furthermore, any minor leakage from the refueling bellows would be collected in a concrete trough below the bellows. The concrete trough is equipped with a drain line that would direct any leakage to the reactor building equipment drain tank and prevent it from entering the seismic gap. The drain line has been checked before refueling outages to confirm that it is not blocked. The only other seal is the gasket for the reactor cavity steel trough drain line. This gasket was replaced after the tests showed that it was leaking. However, the gasket leak was ruled out as the primary source of water observed in the sand bed drains because there is no clear leakage path to the seismic gap. Minor gasket leaks would be collected in the concrete trough below the gasket and would be removed by the drain line similar to leaks from the refueling bellows.

In addition, the applicant noted that additional visual and NDE (dye penetrant) inspections on the reactor cavity stainless steel liner had identified a significant number of cracks, some of which were throughwall cracks. Engineering analysis concluded that the cracks were most probably caused by mechanical impact or thermal fatigue, and not IGSCC. These cracks were determined to be the source of refueling water that passed through the seismic gap. To prevent leakage through the cracks, GPU installed an adhesive-type stainless steel tape to bridge any observed large cracks and subsequently applied a strippable coating. This repair greatly reduced leakage and was implemented every refueling outage while the reactor cavity was flooded.

The applicant noted that it has committed to monitor the sand bed region drains for water leakage. A review of plant documentation did not provide objective evidence that the commitment has been implemented since 1998. Issue Report No. 348545 was issued in accordance with the OGCS corrective action process to document the lapse in implementing the commitment and to reinforce strict compliance with commitment implementation in the future, including during the period of extended operation.

The applicant also committed (Commitment No. 27, Item 4) to performing augmented inspections of the drywell in accordance with ASME Code Section XI, Subsection IWE. These inspections consist of UT examinations of the upper region of the drywell and visual examinations of the protective coating on the exterior of the drywell shell in the sand bed region. UT measurements will supplement the visual inspection of the coating measurements from inside the drywell once before entering the period of operation and every 10 years thereafter during the period of extended operation.

The staff's review of the applicant's response determined that the epoxy coating applied in the sand-bed region of the shell has a limited life and water leakage from the air gap has not been prevented. In view of these observations, the staff requested that the applicant provide a systematic program of examination of the coating that would provide confidence that the preventive measure is adequately implemented at all locations in the sand-pocket areas.

In its response dated June 20, 2006, the applicant committed that it will monitor the sand bed region drains on a daily basis during refueling outages and take the following actions if water is detected. The actions will be completed prior to exiting the outage.

- The source of water will be investigated and diverted, if possible, from entering the gap between the drywell shell and the drywell shield wall.
- The water will be chemically analyzed to aid in determining the source of leakage.
- A remote inspection will be performed in the trough drain area to determine if the trough drains are operating properly.
- The condition of the coating and the moisture barrier (seal) in the affected bays will be inspected.
- If the coating is degraded and visual inspection indicates corrosion is taking place, then UT thickness measurements will be taken in the affected areas of the sand bed region. The measurements will be taken from either inside or outside the drywell to ensure that the shell thickness in areas affected by water leakage is measured. UT thickness measurements and evaluation will be consistent with the existing program.
- The degraded coating and/or the seal will be repaired in accordance with station procedures.
- UT measurements will be taken in the upper region of the drywell consistent with the existing program.

The applicant, also, committed (Commitment No. 27, Item 3) to monitor the sand bed region drains quarterly during the operating cycle. The applicant stated that if water is detected, actions listed below will be taken. Those that require an outage to be accomplished will be completed during the next scheduled refueling outage.

- The leakage rate will be quantified to determine a representative flow rate. The leakage rate will be trended.
- The source of water will be investigated and diverted, if possible, from entering the gap between the drywell shell and the drywell shield wall.
- The water will be chemically analyzed to aid in determining the source of leakage.
- The condition of the coating and the moisture barrier (seal) in the affected bays will be inspected during the next refueling outage or an outage of opportunity.
- If the coating is degraded and visual inspection indicates corrosion is taking place, then UT thickness measurements will be taken in the affected areas of the sand bed region.

The measurements will be taken from either inside or outside the drywell to ensure that the shell thickness in areas affected by water leakage is measured. UT thickness measurements and evaluation of the results will be consistent with the existing program.

- UT measurements will be taken in the upper region of the drywell consistent with the existing program.
- The degraded coating and/or the seal will be repaired in accordance with station procedures.

The staff finds that the applicant's program will provide reasonable assurance that any further incidents of water in the sand bed region will be systematically evaluated, and actions will be taken to prevent further degradation of the drywell shell. However, the program was not clear regarding the extent of the coated surfaces examined during each inspection. This was identified as OI 4.7.2-3 in the SER, dated August 18, 2006.

The applicant committed (Commitment No. 27) to monitoring of the coating on the drywell shell exterior in the sand bed region as part of its ASME Section XI, Subsection IWE Program and of its Protective Coating Monitoring and Maintenance Program. The applicant committed to additional visual inspections of the epoxy coating in all 10 drywell bays at least once prior to the period of extended operation. In a letter dated December 3, 2006, the applicant stated that 100 percent of the epoxy coating had been inspected during the October 2006 outage with no evidence of flaking, blistering, peeling, discoloration or other signs of coating distress. These commitments, with the IWE program and the October 2006 inspection which indicated no coating degradation, resolve the staff concern over the extent of coatings inspection. Therefore, the staff’s concern is resolved and Open Item 4.7.2-3 is closed.

In its letter dated February 15, 2007, the applicant revised a commitment (Commitment No. 27) by adding Item 19, which states that AmerGen will perform an engineering study prior to the proposed renewal period to investigate cost-effective replacement or repair options to eliminate or reduce reactor cavity liner leakage. The ACRS recommended the license be conditioned to require the study. The staff identified this as a license condition consistent with the applicant’s Commitment 27 item 19.

4.7.2.2.6 Ultrasonic Test Measurement Program

In view of the uncertainty regarding the long-term effectiveness of the coating and water leakage, the staff requested that the applicant review the accuracy of the UT measurements and establish a credible program for performing the UT examination of the shell in the sand-bed region during the period of extended operation.

In its response dated June 20, 2006, the applicant stated:

> In a letter dated April 4, 2006, AmerGen committed to perform UT measurements of the sand bed region every 10 years. In view of the uncertainty regarding the long-term effectiveness of the coating and water leakage, the NRC requested the applicant to clarify the commitment for UT measurement frequency in the sand bed region.
>
> AmerGen is confident that the aging management program it committed itself to in the April 4, 2006 letter is adequate to ensure that significant drywell corrosion will be detected and addressed prior to impacting the intended function of the

containment. The program requires visual inspection of the coating in the sand bed region on a frequency of every other refueling outage.

The program also requires performing UT inspections in the upper regions of the drywell shell on a frequency of every other refueling outage. The measurements in the upper region of the drywell bound the sand bed region since the environment is the same and the sand bed region is protected with epoxy coating while the upper region is coated only with a Zinc primer. In addition, AmerGen is committed to performing UT examinations of the sand bed region every 10 years. The 10-year frequency for the UT measurements is based on ASME Section XI requirements and is intended to confirm that the coating continues to mitigate corrosion. The initial UT measurements will be taken prior to entering the period of extended operation. The UT measurements are only a part of the overall program designed to provide reasonable assurance that significant corrosion is detected before containment intended function is adversely impacted.

Nevertheless, AmerGen will take a second set of UT measurements in the sand bed region two refueling outages after the measurements taken prior to entering the period of extended operation. The results of the measurements will be evaluated to determine the appropriate measurement frequency required to provide continued reasonable assurance that corrosion is being effectively monitored and managed during the period of extended operation. The frequency will be established as appropriate, but not to exceed every 10 years. In Item H of the June 20, 2006 response, AmerGen provides additional information on the actions that will be taken if water is detected in the sand bed region drains.

Based on the applicant's commitment (Commitment No. 27), the staff understands that the applicant will take UT measurements in the sand bed region two refueling outages after the measurements taken prior to entering the period of extended operation. The staff's finds this acceptable; therefore, the concern is resolved.

In RAI 4.7.2-4 dated March 10, 2006, the staff noted that industrywide operating experience indicates a number of incidences of torus corrosion in Mark I containments. Neither LRA Table 3.5.2.1.1 nor the ASME Section XI, Subsection IWE Program describes operating experience related to corrosion of the OCGS torus. The staff requested that the applicant provide a summary of the results of IWE inspections performed on the torus and instances of torus corrosion.

In SER Section 3, the staff evaluates the condition of the torus (suppression chamber) and concludes that aging effects will be adequately managed during the period of extended operation.

4.7.2.2.7 Sandia National Laboratories Drywell Structural Analysis

To provide additional assurance that the applicant's AMP (as discussed in Section 3), would provide a framework for insuring that the Oyster Creek drywell shell can withstand the postulated design loads during the renewal period, the NRC staff contracted with Sandia National Laboratories (Sandia) to analyze the drywell with conservatively biased modeling of the degradation. The Sandia analysis is in report SAND2007-0055 (ML070120395), "Structural Integrity Analysis of the Degraded Drywell Containment at the Oyster Creek Nuclear Generating Station," which was issued on January 12, 2007. As part of the analysis, Sandia developed a detailed three-dimensional (3D) finite element model of the drywell containment vessel using information provided by the NRC and the applicant. The model was used to evaluate the structural integrity of the vessel in terms of the stress limits specified in the ASME Boiler and Pressure Vessel (B&PV) Code, Section III, Division I, Subsection NE, and in terms of buckling (stability) limits specified in ASME B&PV Code Case N-284. The purpose of the Sandia analysis was to examine whether the Oyster Creek degraded drywell shell can withstand the postulated loadings without exceeding the ASME code requirements for stress and stability.

The Sandia analysis did not replace or reproduce the analysis done in the GE study. The baseline (i.e. un-degraded) analysis was performed to isolate the effects of the degradation. The Sandia analysis focused more on the relative reduction in design margin due to the corrosion than on the calculated absolute stresses or stability limits.

The Sandia analysis used a different modeling approach than the GE study and made assumptions regarding general design information when plant specific information was unavailable. Analyst judgment was used in applying the ASME Code requirements. Consequently, the numerical values derived by the Sandia analysis are generic in nature and are not part of the Oyster Creek current licensing basis.

The Sandia study included stress and buckling analyses for both a representation of the containment in its degraded condition and in its original, as-built, condition. The study of the as-built conditions provides base-line analyses to assess the effects of degradation on the stresses and buckling behavior for the containment.

The conclusions resulting from the study included:

- The introduction of degradation does cause a noticeable increase in the stress levels throughout the drywell shell for each load condition.

- In general, the accident condition (accident pressure 44 psig, and temperature 292°F) causes the largest stress increases throughout the drywell when degradation is introduced.

- The buckling evaluation performed using ASME N-284 show that based on the loadings and the Sandia model, both the refueling and post-accident load combinations met buckling requirements.

- ASME allowable stresses are met for all three load cases examined.

The effects of locally thinner regions in bays #1 and #13 were explored. Under the refueling load condition, the buckling initiation was observed as a result of these thin areas. However, the effective safety factor was maintained above the ASME minimum of 2.0 for the load combination containing loadings from the refueling activities, the postulated seismic loads, and a hypothetical external pressure load of 2 pounds per square inch.

The Sandia Report results support and confirm that the drywell will be able to perform its intended functions in its present condition. The report also indicates that the areas of the drywell shell above and below the sand bed region have sufficient thickness to accommodate additional corrosion of the shell before ASME Code safety factors or minimum wall thickness criteria are reached. However, in the sand bed region, UT measurements indicate that wall thickness of some areas of the shell are at or near the wall thickness required to satisfy the ASME Code safety factor or the minimum wall thickness criteria.

Additionally, the NRC staff requested Sandia to perform an analysis of the drywell shell with the existing degradation to assess the minimum thickness required in the sand bed area to maintain the minimum safety factors against bucking. Sandia analyzed the shell using the provisions of ASME Section III Code Case N-284. In considering the capacity reduction factor applicable to the load combination incorporating the refueling load and external pressure, Sandia did not give any credit to the membrane tensile stresses produced in the shell by the meridional compressive load, by not increasing capacity reduction factor. Sandia arrived at a minimum thickness of 0.844".

In the staff's SER dated April 14, 1992, the staff had made an assessment of the GE analysis for the load combination incorporating the refueling load and external pressure. The SER and attached Technical Evaluation Report by Brookhaven National Laboratory documented the staff's review of the increased capacity reduction factor due to the membrane tension, and accepted the process of deriving the increased capacity reduction factor. The GE analysis assumed a uniform minimum thickness in the sand bed region of 0.736". The Staff finds the use of the increased capacity reduction factor described in the GE analysis is reasonable and consistent with ASME Code Case N-284 as well as ASME Section VIII, Code Case 2286.

Based on its review and the applicant's Commitment 27, the staff identified a licensing condition that requires the applicant to monitor the shell degradation in all 10 bays of the sand bed region every other refueling outage throughout the renewal period.

During the Advisory Committee on Reactor Safeguards (ACRS) meeting on February 1, 2007, the applicant committed to perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operations. In its letter dated February 15, 2007, the applicant revised a license commitment (Commitment No. 27) by adding Sub-item 18, which states that AmerGen will perform a 3-D finite elemental analysis of the primary containment drywell shell using modern methods and current drywell shell thickness data to better quantify the margin that exists above the Code requirement for buckling. The staff identified this commitment item as a license condition.

4.7.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of drywell corrosion in LRA Section A.4.5.2.

The staff's review of LRA Section A.4.5.2 identified an area in which additional information was necessary to complete the review of drywell corrosion.

In RAI 4.7.2-5 dated March 10, 2006, the staff noted that for this important issue the UFSAR supplement should, at a minimum, briefly describe the quantitative aspect of the drywell corrosion and the applicant's assertions to maintain it above a certain thickness to ensure that the containment can perform its intended function during the period of extended operation. The applicant will use the TLAA and Subsection IWE of the ASME Code to maintain the containment functionality.

In its response dated April 26, 2006, the applicant stated that UFSAR Section 3.8.2.8 provides historical information on drywell corrosion and corrective actions taken to control it. The section also describes aging management activities that are implemented during the current term consistent with the existing commitments to NRC. The section is revised periodically to include, by reference, the results of quantitative engineering analyses, the UT measurements in the upper regions of the drywell, and inspection of the coating of the drywell shell in the sand bed region.

The applicant stated that LRA Section A.1.27, ASME Code Section XI, Subsection IWE, and the license renewal commitment list (Commitment No. 27), which are included in the application, will be incorporated in the UFSAR as a supplement. However, the applicant recognizes that both the LRA Appendix A and the commitment list do not include additional commitments to the NRC staff on drywell corrosion for the period of extended operation. Hence, the applicant stated that it will revise the commitment list to include details of these additional commitments and will use it as the basis for the drywell corrosion aging management program during the period of extended operation. The revised commitment list and LRA Section A.1.27 will be incorporated in the UFSAR. The supplement, therefore, will include elements of the drywell corrosion aging management program in sufficient detail to ensure that program commitments are documented in the UFSAR.

In a letter dated December 3, 2006, the applicant provided additional commitments for enhancing the ASME Section XI, Subsection IWE aging management program. The new commitment 27 items are:

14. UT thickness measurements will be taken from outside the drywell in the sand bed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.

15. Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sand bed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay #13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are Identified.

16. Perform visual inspections of the drywell shell inside the trenches in bay #5 and bay #17 and take UT measurements inside these trenches in 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas.

17. Perform visual inspection of the moisture barrier between the drywell shell and the concrete floor curb, installed inside the drywell during the October 2006 refueling outage, in accordance with ASME Section XI, Subsection IWE during the period of extended operation.

During the Advisory Committee on Reactor Safeguards (ACRS) meeting on February 1, 2007, the applicant committed to perform an engineering study prior to the period of extended operation in order to identify options to eliminate or reduce the leakage in the refueling cavity liner. The applicant also committed to perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

In its letter dated February 15, 2007, the applicant confirmed the commitments it made to the ACRS and revised commitment 27) ASME Section XI, Subsection IWE. The applicant also added commitments for inspection of the drywell trenches and full scope of drywell sand bed region inspections. The specific commitment items which the applicant added are:

18. AmerGen will perform a 3-D finite element structural analysis of the primary containment drywell shell using modern methods and current drywell shell thickness data to better quantify the margin that exists above the Code required minimum for buckling. The analysis will include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect Code margins. If the analysis determines that the drywell shell does not meet required thickness values, the NRC will be notified in accordance with 10 CFR 50 requirements.

19. AmerGen will perform an engineering study to investigate cost-effective replacement or repair options to eliminate or reduce reactor cavity liner leakage.

20. AmerGen is committed to perform visual and UT inspections of the drywell shell in the inspection trenches in drywell bays #5 and #17 during the Oyster Creek 2008 refueling outage (see item 16 of AmerGen's IWE Program (Commitment 27), made in its letter 2130-06-20426). AmerGen will extend this commitment and also perform these inspections during the 2010 refueling outage. In addition, AmerGen will monitor the two trenches for the presence of water during refueling outages. Visual and UT inspections of the shell within the trenches will continue to be performed until no water is identified in the trenches for two consecutive refueling outages, at which time the trenches will be restored to their original design configuration (e.g., refilled with concrete) to minimize the risk of future corrosion.

21. Perform the full scope of drywell sand bed region inspections prior to the period of extended operation and then every other refueling outage thereafter. The full scope is defined as:

    - UT measurements from inside the drywell (Item 1)
    - Visual inspections of the drywell external shell epoxy coating in all 10 bays (Item4)
    - Inspection of the seal at the junction between the sand bed region concrete and the embedded drywell shell (Item 12)
    - UT measurements at the external locally thinned areas inspected in 2006 (Items 9 and 14)

The staff, consistent with ACRS recommendations, identified these items as license conditions.

The staff finds the applicant's additional commitments for enhancing the ASME Section XI, Subsection IWE aging management program acceptable; therefore, the concern described in RAI 4.7.2-5 is resolved.

On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address drywell corrosion is adequate.

4.7.2.4 Conclusion

On the basis of its review and the license conditions discussed above, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the drywell corrosion TLAA, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the activities for managing the effects of aging and the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.3 Equipment Pool and Reactor Cavity Walls Rebar Corrosion

4.7.3.1 Summary of Technical Information in the Application

In LRA Section 4.7.3, the applicant summarized the evaluation of equipment pool and reactor cavity walls rebar corrosion for the period of extended operation. A letter to the NRC discussing

Section 5

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The NRC staff issued its safety evaluation report (SER) with open items related to the renewal of the operating license for Oyster Creek Generating Station (OCGS) on August 18, 2006. On October 3, 2006, the applicant presented its license renewal application, and the staff presented its findings to the ACRS Plant License Renewal Subcommittee.

The NRC staff issued an updated SER on December 29, 2006. On January 18, 2007, the applicant presented its license renewal application, the staff presented its review findings and the representative for the interveners presented their information, which were associated with drywell shell integrity, to the ACRS Plant License Renewal Subcommittee.

During the 539th meeting of the ACRS on February 1, 2007, the ACRS completed its review of the Oyster Creek license renewal application and the NRC staff's SER. The ACRS documented its findings in a letter to the Commission dated February 8, 2007. A copy of this letter and the staff's response is provided on the following pages of this SER Section.

Consistent with ACRS recommendation, the staff added two additional license conditions to the SER.

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

RSR-2233

February 8, 2007

The Honorable Dale E. Klein
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE OYSTER CREEK GENERATING STATION

Dear Chairman Klein:

During the 539th meeting of the Advisory Committee on Reactor Safeguards, February 1-3, 2007, we completed our review of the license renewal application for the Oyster Creek Generating Station (OCGS) and the updated Safety Evaluation Report (SER) prepared by the NRC staff. Our Plant License Renewal Subcommittee also reviewed this matter during meetings on October 3, 2006 and January 18, 2007. During these reviews, we had the benefit of discussions with representatives of the NRC staff and its contractor Sandia National Laboratories (SNL), members of the public, and AmerGen Energy Company, LLC (AmerGen) and its contractors. We also had the benefit of the documents referenced. This report fulfills the requirements of 10 CFR 54.25 that the ACRS review and report on all license renewal applications.

RECOMMENDATIONS

1. With the incorporation of the conditions described in Recommendations 2, 3, and 4, the application for license renewal for OCGS should be approved.

2. We concur with the staff's proposal to impose license conditions to increase the frequency of the drywell inspections and to monitor the two drywell trenches to ensure that the sources of water are identified and eliminated.

3. The staff should add a license condition to ensure that the applicant fulfills its commitment to perform an engineering study prior to the period of extended operation to identify options to eliminate or reduce the leakage in the OCGS refueling cavity liner.

4. The staff should add a license condition to ensure that the applicant fulfills its commitment to perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

DISCUSSION

The Oyster Creek Generating Station is located in Lacey Township, Ocean County, New Jersey, approximately 2 miles south of the community of Forked River, 2 miles inland from the shore of Barnegat Bay, and 9 miles south of Toms River, New Jersey. The NRC issued the provisional operating license for OCGS on April 9, 1969 and the operating license on July 2, 1991. OCGS is a single unit facility with a single cycle, forced circulation boiling water reactor (BWR)-2 with a Mark 1 containment. The nuclear steam supply system was furnished by General Electric and the balance of the plant was originally designed and constructed by Burns & Roe. The licensed power output is 1930 MWt with a design electrical output of approximately 650 MWe. The applicant, AmerGen requested renewal of the OCGS operating license for 20 years beyond the current license term, which expires on April 9, 2009.

During the 1980s, the licensee discovered corrosion on the outside wall of the OCGS drywell shell. Although some corrosion had occurred in the upper shell region, the majority had occurred in a region near the base of the shell where the shell was partially supported by a sand bed. The licensee determined that water had been leaking through flaws in the refueling cavity liner during refueling operations. This water had migrated down the outside of the drywell shell and into the sand bed. As part of the corrective actions, the licensee removed the sand and applied an epoxy coating to the outside of the shell in the sand bed region. In addition, repairs were made to the refueling pool liner and the concrete drain trough under the refueling seal. These repairs reduced the leakage and routed any leakage to a drain line rather than down the outside of the drywell shell. To further reduce leakage, the licensee applied strippable coatings to the liner during all but one of the subsequent refueling outages. The licensee performed ultrasonic testing (UT) to determine the as-found condition of the drywell shell and performed a structural analysis in 1992 to demonstrate acceptability of the containment in the degraded condition.

The 1992 structural analysis was reviewed and approved by the NRC staff. This analysis included a determination of the stresses in the thinned region under the design pressure loads and an evaluation of the potential for buckling during normal operations and postulated accident conditions. The buckling analysis utilized American Society of Mechanical Engineers (ASME) Code Case N-284, Revision 1. The staff accepted the use of this Code Case in the 1992 analysis. In support of the review of the OCGS license renewal application, the staff had SNL perform a confirmatory structural analysis. Both analyses demonstrated that the drywell shell met the minimum ASME Code requirements for buckling. However, the amount of margin above the Code minimum depended on the applicability of the increase in the buckling capacity due to tensile stresses orthogonal to the applied compressive stresses computed according to the Code Case. During the January 18, 2007 meeting, the Subcommittee requested additional justification for using the increased capacity factor. At our February meeting, Dr. C. Miller, the author of the ASME Code Case, described the technical basis for the Code Case and presented test results to demonstrate that the increased capacity factor was applicable to OCGS. The increased capacity factor used in the 1992 analysis provided by the applicant was based on results for metal cylinders. Dr. Miller showed results of tests conducted on metal spheres which demonstrated that the results for cylinders were conservative for spherical shells. The staff reaffirmed its position that the use of the increased capacity factor is appropriate for the analysis of the OCGS drywell shell. We concur with this position.

The 1992 structural analysis was based on the assumption that the shell is uniformly thinned in the sand bed region. The applicant has committed to perform a 3-D finite-element analysis of the

OGCS drywell to determine the margin of the shell in the as-found condition using modern methods. This analysis will provide a more accurate quantification of the margin above the Code required minimum for buckling. The applicant has committed to complete the analysis prior to the period of extended operation. We commend the applicant for this action and would like to be briefed by the staff on the results when they become available. Although it is anticipated that the analysis will demonstrate additional margin above the Code required minimum, the applicant should complete this analysis in a timely manner prior to entering the period of extended operation in order to identify and resolve any unexpected results. The analysis should include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect the Code margins. The staff should impose a license condition to ensure that the applicant completes the analysis prior to entering the period of extended operation.

In 2006, the applicant performed additional UT and visual inspections of the drywell shell. When compared to the previous UT, the 2006 results confirmed that the corrective actions taken in the sand bed region had been effective and that the corrosion had been arrested or at least that the corrosion rates were very low (i.e., within the data scatter). The epoxy coating appeared in very good condition with no evidence of degradation which is also consistent with the conclusion that the corrosion has been effectively arrested. These examinations also demonstrated that the corrosion rate in the upper shell region and the embedded floor regions remained sufficiently low to demonstrate structural integrity during the period of extended operation. The applicant has committed to perform UT and visual inspections of the drywell shell during the period of extended operation. Because of the relatively small margin above the Code minimum against buckling in the sand bed region shown by current analyses, the staff is proposing a license condition to increase the frequency of drywell inspections and UT in the sand bed region to all 10 bays every other refueling outage for the extended period of operation. Increased inspections will result in additional radiation exposure to personnel involved in the inspections. Therefore, the applicant should be allowed to increase the period between inspections if it demonstrates increased margin through analysis or if the ongoing inspections continue to demonstrate that the corrosion has been sufficiently arrested. With this provision, we agree with this license condition.

The 2006 examinations revealed that when the cavity was flooded for refueling, water leakage was still occurring. This leakage of approximately 1 gallon per minute is well within the capacity of the drain as long as the drain system is working properly. The purpose of the drain system is to catch water that may leak past a failed refueling seal or liner and divert the water to sumps, and prevent it from coming into contact with the outside of the drywell shell. Leakage is not expected to occur as part of normal operation with properly maintained equipment and structures. The applicant has committed to continue monitoring for leakage of the refueling cavity liner and other water sources associated with the drywell. The applicant has also committed to complete an engineering study to identify cost-effective repair or replacement options to eliminate the refueling cavity liner leakage. The engineering study will be completed prior to entering the period of extended operation. We agree that efforts should be made to eliminate routine leakage in order to provide increased protection against further degradation. The staff should impose a license condition to ensure the study is completed by the applicant prior to the period of extended operation.

During the 2006 refueling outage, the applicant discovered water in two trenches that had been previously excavated to allow access to and inspection of the inside of the shell in the embedded region. The applicant determined that the water had come from normal operation and maintenance activities. The water had migrated to the trenches due to a blocked drain tube in the sub-pile area and the lack of a seal between the shell and concrete curb. The applicant repaired the drain tube and installed a seal in the gap between the shell and concrete curb. The applicant intends to fill these trenches after two consecutive outages in which no water is observed. Having the trenches open is beneficial for identifying drainage issues, but it increases the risk of additional corrosion because it provides an open area in which water can be trapped against the shell. The staff is proposing a license condition that would require the applicant to leave the trenches open and monitor them during each refueling outage until such time that the applicant can demonstrate that the water sources have been identified and eliminated. We agree with the monitoring of the trenches to ensure the elimination of the sources of water. However, leaving the trenches open longer than necessary increases the risk of future corrosion. Therefore, the applicant should not be unnecessarily delayed in repairing the trenches. With this provision, we agree with the license condition proposed by the staff.

In the updated SER, the staff documents its review of the license renewal application and other information submitted by AmerGen and obtained during an audit and inspections conducted at the plant site. The staff reviewed the completeness of the applicant's identification of structures, systems, and components (SSCs) that are within the scope of license renewal; the integrated plant assessment process; the applicant's identification of the plausible aging mechanisms associated with passive, long-lived components; the adequacy of the applicant's aging management programs (AMPs); and the identification and assessment of time-limited aging analyses (TLAAs) requiring review.

The OCGS application either demonstrates consistency with the Generic Aging Lessons Learned (GALL) Report or documents deviations from the approaches specified in the GALL Report. The staff reviewed this application in accordance with NUREG-1800, the "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants."

The applicant identified those SSCs that fall within the scope of license renewal. For these SSCs, the applicant performed a comprehensive aging management review. Based on the results of this review, the applicant will implement 57 AMPs for license renewal including existing, enhanced, and new programs. In the SER, the staff concludes that the applicant has appropriately identified SSCs within the scope of license renewal and that the AMPs described by the applicant are appropriate and sufficient to manage aging of long-lived passive components that are within the scope of license renewal. With the incorporation of the license conditions described in Recommendations 2, 3 and 4, we agree with this conclusion.

The staff conducted inspections and an audit of the license renewal application. The purpose of the inspections was to verify that the scoping and screening methodologies are consistent with the regulations and are adequately reflected in the application. In addition, the inspectors personally examined selected areas of the sand bed region to verify the condition of the epoxy coating. The audit confirmed the appropriateness of the AMPs and the aging management reviews. Based on the inspections and audit, the staff concluded that these programs are consistent with the descriptions contained in the OCGS license renewal application. The staff also concluded that the existing programs, to be credited as AMPs for license renewal, are generally functioning well and that the applicant has established an implementation plan in its commitment tracking system to ensure timely completion of the license renewal commitments.

The applicant identified those systems and components requiring TLAAs and reevaluated them for 20 more years of operation. Affected TLAAs include those associated with neutron embrittlement, metal fatigue, irradiation-assisted stress corrosion cracking, environmental qualification of electrical equipment, and stress relaxation of hold-down bolts. The staff concluded that the applicant has provided an adequate list of TLAAs. Further, the staff concluded that in all cases the applicant has met the requirements of the license renewal rule by demonstrating that the TLAAs will remain valid for the period of extended operation, or that the TLAAs have been projected to the end of the period of extended operation, or that the aging effects will be adequately managed for the period of extended operation. With the incorporation of the license conditions described in Recommendations 2, 3 and 4, we concur with the staff that OCGS TLAAs have been properly identified and that criteria supporting 20 more years of operation have been met.

With the incorporation of the license conditions described in Recommendations 2, 3, and 4, no issues related to the matters described in 10 CFR 54.29(a)(1) and (a)(2) preclude renewal of the operating license for OCGS. The programs established and committed to by AmerGen provide reasonable assurance that OCGS can be operated in accordance with its current licensing basis for the period of extended operation without undue risk to the health and safety of the public and the NRC should approve the AmerGen application for renewal of the operating license for OCGS.

Sincerely,

/RA/

William J. Shack
Chairman

<u>References</u>:

- Updated Safety Evaluation Report Related to the License Renewal of Oyster Creek Generating Station, December 29, 2006.

- Safety Evaluation Report with Open Items Related to the License Renewal of the Oyster Creek Generating Station, August 18, 2006.

- Oyster Creek Generating Station- Application for Renewed Operating Licenses, July 22, 2005.

- Supplemental Information Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application, June 20, 2006.

- Audit and Review Report for Plant Aging Management Reviews and Programs- Oyster Creek Generating Station August 18, 2006.

- Supplemental Response to NRC Request for Additional Information (RAI 2.5.1.19-1), dated September 28, 2005, Related to Oyster Creek Generating Station License Renewal Application, November 11, 2005.

- Oyster Creek Generating Station - NRC License Renewal Inspection Report 05000219/2006007, September 21, 2006

- Memorandum dated December 14, 2006 from Louise Lund to John Larkins, Subject: Review Background Materials for the Meeting of the License Renewal Subcommittee Scheduled on January 18, 2007, Related to the Interim Review of the License Renewal of the Oyster Creek Generating Station. ML063470557

- Memorandum date December 8, 2006 from Michael P. Gallagher to the U.S. Nuclear Regulatory Commission, Subject: Submittal of Information to ACRS Plant License Renewal Subcommittee Related to AmerGen's Application for Renewed Operating License for Oyster Creek Generating Station. ML063470532

- Sandia National Laboratories Report "Structural Integrity Analysis of the Degraded Drywell Containment at the Oyster Creek Nuclear Generating Station," January 2007

- ASME Code Case N-284-1, "Metal Containment Shell Buckling Design Methods, Class MC, Section III, Division one, March 14, 1995."

- Letter dated January 31, 2007, from Senator Frank Lautenberg, Senator Robert Menendez, Representative Christopher H. Smith, and Representative Jim Saxton to The ACRS.

- Letter dated January 31, 2007 from Richard Webster, Rutgers Environmental Law Clinic to the ACRS, regarding the Safety Evaluation Report for Oyster Creek Nuclear Power Plant.

- Oyster Creek Generating Station-NRC In-Service Inspection and License Renewal Commitment Followup Inspection Report 0500021/2006013, January 17, 2007.

March 8, 2007

Dr. William J. Shack, Chairman
Advisory Committee on Reactor Safeguards
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: RESPONSE TO ADVISORY COMMITTEE ON REACTOR SAFEGUARDS REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE OYSTER CREEK GENERATING STATION

Dear Dr. Shack:

During the 539th meeting of the Advisory Committee on Reactor Safeguards (ACRS or the Committee) held on February 1–3, 2007, the ACRS completed its review of the license renewal application (LRA) for the Oyster Creek Generating Station (OCGS) and the associated final safety evaluation report (SER) prepared by the U.S. Nuclear Regulatory Commission (NRC) staff. In its final report, the Committee recommends renewal of the OCGS operating license in conjunction with the recommendations discussed in your letter dated February 8, 2007. The staff appreciates the Committee's expeditious, objective, and in-depth review of the LRA and the staff's final SER. The staff agrees with the Committee's recommendations:

1. The staff will impose a license condition to increase the frequency of the drywell inspections and to monitor the two drywell trenches to ensure that the sources of water are identified and eliminated.

2. The staff will ensure that the applicant fulfills its commitment to (a) perform an engineering study prior to the period of extended operation to identify options to eliminate or reduce the leakage in the OCGS refueling cavity liner, and (b) perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

The staff recognizes the ACRS's commitment to safety and appreciates the Committee's continued support of the license renewal process.

Sincerely,

/RA/

Luis A. Reyes
Executive Director
for Operations

cc: Chairman Klein
Commissioner McGaffigan
Commissioner Merrifield
Commissioner Jaczko
Commissioner Lyons
SECY

March 8, 2007

Dr. William J. Shack, Chairman
Advisory Committee on Reactor Safeguards
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: RESPONSE TO ADVISORY COMMITTEE ON REACTOR SAFEGUARDS REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE OYSTER CREEK GENERATING STATION

Dear Dr. Shack:

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1. The staff will impose a license condition to increase the frequency of the drywell inspections and to monitor the two drywell trenches to ensure that the sources of water are identified and eliminated.

2. The staff will ensure that the applicant fulfills its commitment to (a) perform an engineering study prior to the period of extended operation to identify options to eliminate or reduce the leakage in the OCGS refueling cavity liner, and (b) perform a 3-D (dimensional) finite-element analysis of the drywell shell prior to entering the period of extended operation.

The staff recognizes the ACRS's commitment to safety and appreciates the Committee's continued support of the license renewal process.

Sincerely,
/RA/
Luis A. Reyes
Executive Director
for Operations

cc: Chairman Klein
Commissioner McGaffigan
Commissioner Merrifield
Commissioner Jaczko
Commissioner Lyons
SECY

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DATE:	02/26/07	02/27/07	03/02/07	03/08/07

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Letter to W. Shack, from L. Reyes, dated: March 8, 2007

SUBJECT: RESPONSE TO ADVISORY COMMITTEE ON REACTOR SAFEGUARDS REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR OYSTER CREEK GENERATING STATION

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Section 6

SECTION 6

CONCLUSION

The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) reviewed the license renewal application (LRA) for Oyster Creek Generating Station in accordance with the NRC regulations and NUREG-1800, Revision 1, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,” dated September 2005. Title 10, Section 54.29, of the *Code of Federal Regulations* (10 CFR 54.29) provides the standards for issuance of a renewed license.

On the basis of its review, the staff concludes that the applicant adequately identified those systems and components that are within the scope of license renewal, as required by 10 CFR 54.4(a), and those systems and components that are subject to an aging management review, as required by 10 CFR 54.21(a)(1). The staff also concludes that the applicant demonstrated that the aging effects will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis (CLB) for the period of extended operation, as required by 10 CFR 54.21(a)(3). Further, the staff concludes that the applicant demonstrated that (1) the time-limited aging analyses (TLAAs) will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i), (2) the TLAAs had been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii), or (3) that the aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). On the basis of its evaluation of the LRA, the staff finds that the requirements of 10 CFR 54.29(a) have been met, that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the plant’s CLB in order to comply with this paragraph are in accord with the Act and the Commission’s regulations.

The staff notes that any requirements of Subpart A of 10 CFR Part 51 are documented in Supplement 28 to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Oyster Creek Nuclear Generating Station Final Report," dated January 2007 (ML070100234).

Appendix A Excerpts

APPENDIX A

COMMITMENTS FOR LICENSE RENEWAL OF OCGS

During the review of the Oyster Creek Generating Station (OCGS) license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff), AmerGen Energy Company, LLC (the applicant) made commitments related to aging management programs (AMPs) to manage the aging effects of structures and components (SCs) both prior to and during the period of extended operation. The following table lists these commitments along with the implementation schedules and the sources for each commitment.

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	pipe or component has not been previously replaced or recoated, if any such locations remain. (2) Fire protection components in the scope of the program. (3) Piping located inside the vault in the scope of the program. The vault is considered a manhole that is located between the reactor building and the exhaust tunnel.			
27) ASME Section XI, Subsection IWE	Existing program is credited. The program will be enhanced to include: (1) Ultrasonic Testing (UT) thickness measurements of the drywell shell in the sand bed region will be performed on a frequency of every 10 years, except that the initial inspection will occur prior to the period of extended operation and the subsequent inspection will occur two refueling outages after the initial inspection, to provide early confirmation that corrosion has been arrested. The UT measurements will be taken from the inside of the drywell at the same locations where UT measurements were performed	A.1.27	Prior to the period of extended operation. Prior to the period of extended operation (completed during 2006 refueling outage); then every other refueling outage	Section B.1.27 Letter 2130-06-20354 Letter 2130-06-20358 Letter 2130-07-20464 Letter 2130-06-20358

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	in 1996. The inspection results will be compared to previous results. Statistically significant deviations from the 1992, 1994, and 1996 UT results will result in corrective actions that include the following: • Perform additional UT measurements to confirm the readings. • Notify NRC within 48 hours of confirmation of the identified condition. • Conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected. • Perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity. • Perform operability determination and justification for operation until next inspection.			

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	These actions will be completed prior to restart from the associated outage. Note: The frequency for the inspections described in item 1 (above) has been changed to every other refueling outage, in accordance with item 21 of the IWE Inspection Program. (2) A strippable coating will be applied to the reactor cavity liner to prevent water intrusion into the gap between the drywell shield wall and the drywell shell during periods when the reactor cavity is flooded. (3) The reactor cavity seal leakage trough drains and the drywell sand bed region drains will be monitored for leakage. • The sand bed region drains will be monitored daily during refueling outages. If leakage is detected, procedures will be in place to determine the source of leakage and investigate and address the impact of leakage on the drywell		Refueling outages prior to and during the period of extended operation Periodically Daily during refueling outages.	

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	shell, including verification of the condition of the drywell shell coating and moisture barrier (seal) in the sand bed region and performance of UT examinations of the shell in the upper regions. UTs will also be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred. UT results will be evaluated per the existing program. Any degraded coating or moisture barrier will be repaired. These actions will be completed prior to exiting the associated outage. • The sand bed region drains will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated, corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage:		Quarterly during non-outage periods.	

COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	• Inspection of the drywell shell coating and moisture barrier (seal) in the affected bays in the sand bed region • UTs of the upper drywell region consistent with the existing program • UTs will be performed on any areas in the sand bed region where visual inspection indicates the coating is damaged and corrosion has occurred • UT results will be evaluated per the existing program. • Any degraded coating or moisture barrier will be repaired. (4) Prior to the period of extended operation, AmerGen will perform additional visual inspections of the epoxy coating that was applied to the exterior surface of the Drywell shell in the sand bed region, such that the coated surfaces in all 10 Drywell bays will have been inspected at least once. In addition, the Inservice Inspection (ISI) Program will be enhanced to require inspection of 100% of the epoxy coating		Prior to the period of extended operation (completed during 2006 refueling outage); then every other refueling outage thereafter	

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	every 10 years during the period of extended operation. These inspections will be performed in accordance with ASME Section XI, Subsection IWE. Performance of the inspections will be staggered such that at least three bays will be examined every other refueling outage. Note: The scope and frequency for the inspections described in item number4 (above) has been changed to all 10 bays every other refueling outage, in accordance with item 21 of the IWE Inspection Program.			
	(5) A visual examination of the drywell shell in the drywell floor inspection access trenches will be performed to assure that the drywell shell remains intact. If degradation is identified, the drywell shell condition will be evaluated and corrective actions taken as necessary. In addition, one-time ultrasonic testing (UT) measurements will be taken to confirm the adequacy of the shell thickness in these areas. Beyond these examinations,		Prior to the period of extended operation (completed during 2006 refueling outage)	

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	these surfaces will either be inspected as part of the scope of the ASME Section XI, Subsection IWE inspection program or they will be restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas. Note: Item 5 (above) is supplemented by Item numbers 16 and 20 of the IWE Inspection Program.			
	(6) The coating inside the torus will be visually inspected in accordance with ASME Section XI, Subsection IWE, per the Protective Coatings Program. The scope of each of these inspections will include the wetted area of all 20 torus bays. Should the current torus coating system be replaced, the inspection frequency and scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE.		Every other refueling outage prior to (completed during 2006 refueling outage) and during the period of extended operation.	Letter 2130-06-20426
	(7) AmerGen will conduct UT thickness measurements in the upper regions of the drywell shell every other refueling outage		Every other refueling outage prior to (completed during 2006 refueling	

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	at the same locations as are currently measured.		outage) and during the period of extended operation	
	(8) The IWE Program will be credited for managing corrosion in the Torus Vent Line and Vent Header exposed to an Indoor Air (External) environment.			
	(9) During the next UT inspections to be performed on the drywell sand bed region (reference AmerGen 4/4/06 letter to NRC), an attempt will be made to locate and evaluate some of the locally thinned areas identified in the 1992 inspection from the exterior of the drywell. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements for these locally thinned areas may be taken from either inside the drywell or outside the drywell (sand bed region) to limit radiation dose to as low as reasonably achievable (ALARA).		Prior to the period of extended operation (completed during 2006 refueling outage); then every other refueling outage thereafter	

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	Note: Item 9 (above) is supplemented by Items 14 and 21 of the IWE Inspection Program. (10) AmerGen will conduct UT thickness measurements on the 0.770 inch thick plate at the junction between the 0.770 inch thick and 1.154 inch thick plates, in the lower portion of the spherical region of the drywell shell. These measurements will be taken at four locations using the 6”x6” grid. The specific locations to be selected will consider previous operational experience (i.e., will be biased toward areas that have experienced corrosion or have been exposed to water leakage). These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).		Prior to the period of extended operation and two refueling outages later.	

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
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	(11) AmerGen will conduct UT thickness measurements in the drywell shell “knuckle” area, on the 0.640 inch thick plate above the weld to the 2.625 inch thick plate. These measurements will be taken at four locations using the 6”x6” grid. The specific locations to be selected will consider previous operational experience (i.e., will be biased toward areas that have experienced corrosion or have been exposed to water leakage). These measurements will be performed prior to the period of extended operation and repeated at the second refueling outage after the initial inspection, at the same location. If corrosion in this transition area is greater than areas monitored in the upper drywell, UT inspections in the transition area will be performed on the same frequency as those in the upper drywell (every other refueling outage).		Prior to the period of extended operation and two refueling outages later.	
	(12) When the sand bed region drywell shell coating inspection is performed (Commitment 27, Items 4 and 21), the seal at the junction between the sand bed		Prior to the period of extended operation (completed during 2006 refueling outage); then every	

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COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	region concrete and the embedded drywell shell will be inspected per the Protective Coatings Program. Note: The frequency for the inspections described in Item 12 (above) has been changed to every other refueling outage, in accordance with Item 21 of the IWE Inspection Program		other refueling outage thereafter.	
	(13) The reactor cavity concrete trough drain will be verified to be clear from blockage once per refueling cycle. Any identified issues will be addressed via the corrective action process.		Once per refueling cycle.	
	(14) UT thickness measurements will be taken from outside the drywell in the sand bed region during the 2008 refueling outage on the locally thinned areas examined during the October 2006 refueling outage. The locally thinned areas are distributed both vertically and around the perimeter of the drywell in all ten bays such that potential corrosion of the drywell shell would be detected.		During the 2008 refueling outage and every other refueling outage thereafter	

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	Note: The frequency for the inspections described in Item 14 (above) has been change to every other refueling outage, in accordance with Item 21 of the IWE Inspection Program. (15) Starting in 2010, drywell shell UT thickness measurements will be taken from outside the drywell in the sand bed region in two bays per outage, such that inspections will be performed in all 10 bays within a 10-year period. The two bays with the most locally thinned areas (bay #1 and bay # 13) will be inspected in 2010. If the UT examinations yield unacceptable results, then the locally thinned areas in all 10 bays will be inspected in the refueling outage that the unacceptable results are Identified. Note: The scope and frequency for the inspections described in Item 15 (above) have been changed to all 10 bays every other refueling outage, in accordance with Item 21 of the IWE Inspection Program.		All 10 bays will be inspected during the 2008 refueling outage and every other refueling outage thereafter. During the 2008	

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	**ITEM NUMBER AND COMMITMENT**	**UFSAR SUPPLEMENT LOCATION (LRA APP. A)**	**ENHANCEMENT OR IMPLEMENTATION SCHEDULE**	**SOURCE**
	(16) Perform visual inspections of the drywell shell inside the trenches in bay # 5 and bay # 17 and take UT measurements inside these trenches In 2008 at the same locations examined in 2006. Repeat (both the UT and visual) inspections at refueling outages during the period of extended operation until the trenches are restored to the original design configuration using concrete or other suitable material to prevent moisture collection in these areas. Note: Item 16 (above) is supplemented by Item 20 of the IWE Inspection Program		refueling outage and subsequent refueling outages until trenches are restored to original configuration.	
	(17) Perform visual inspection of the moisture barrier between the drywell shell and the concrete floor curb, installed inside the drywell during the October 2006 refueling outage, in accordance with ASME Section XI, Subsection IWE during the period of extended operation.		In accordance with ASME Section XI, Subsection IWE.	
	(18) AmerGen will perform a 3-D finite element structural analysis of the primary		Prior to the period of extended operation	

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	containment drywell shell using modern methods and current drywell shell thickness data to better quantify the margin that exists above the Code required minimum for buckling. The analysis will include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect Code margins. If the analysis determines that the drywell shell does not meet required thickness values, the NRC will be notified in accordance with 10 CFR 50 requirements. (19) AmerGen will perform an engineering study to investigate cost-effective replacement or repair options to eliminate or reduce reactor cavity liner leakage. (20) AmerGen is committed to perform visual and UT inspections of the drywell shell in the inspection trenches in drywell bays 5 and 17 during the Oyster Creek 2008 refueling outage (see item 16 of AmerGen's IWE Program (commitment 27), made in its letter 2130-06-20426). AmerGen will extend this commitment		Prior to the period of extended operation	

COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	and also perform these inspections during the 2010 refueling outage. In addition, AmerGen will monitor the two trenches for the presence of water during refueling outages. Visual and UT inspections of the shell within the trenches will continue to be performed until no water is identified in the trenches for two consecutive refueling outages, at which time the trenches will be restored to their original design configuration (e.g., refilled with concrete) to minimize the risk of future corrosion.			
	(21) Perform the full scope of drywell sand bed region inspections prior to the period of extended operation and then every other refueling outage thereafter. The full scope is defined as: • UT measurements from inside the drywell (Item 1) • Visual inspections of the drywell external shell epoxy coating in all 10 bays (Item 4)		During the 2008 refueling outage and every other refueling outage thereafter. If the analysis being performed under Item 18 above establishes increased margin, or if ongoing inspections continue to demonstrate that drywell corrosion has	

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF OCGS				
COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	• Inspection of the seal at the junction between the sand bed region concrete and the embedded drywell shell (Item 12) • UT measurements at the external areas inspected in 2006 (Items 9 and 14)		been sufficiently arrested, the period between inspections may able increased to minimize personnel radiation exposure.	
28) ASME Section XI, Subsection IWF	Existing program is credited. The scope of the program will be enhanced to include additional MC supports, and require inspection of the underwater supports for loss of material due to corrosion and loss of mechanical function and loss of preload on bolting by inspecting for missing, detached, or loosened bolts.	A.1.28	Prior to the period of extended operation.	Section B.1.28
29) 10 CFR Part 50, Appendix J	Existing program is credited.	A.1.29	Ongoing	Section B.1.29
30) Masonry Wall Program	Existing program is credited. The Masonry Wall Program is part of the Structures Monitoring Program.	A.1.30	Ongoing	Section B.1.30

COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	evaluation will be performed to determine if identified degradation warrants more frequent inspection or corrective actions.			
33) Protective Coating Monitoring and Maintenance Program	Existing program is credited. The Oyster Creek Protective Coating Monitoring and Maintenance 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 sand bed region. The program will be enhanced to include: (1) 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. (2) Additional visual inspections of the epoxy coating that was applied to the exterior surface of the drywell shell in the sand bed region, such that the coated surfaces in all 10 drywell bays will have been inspected at least once prior to entering the period of extended operation.	A.1.33	Prior to the period of extended operation.	Section B.1.33 Letter 2130-06-20354

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COMMITMENT NUMBER	ITEM NUMBER AND COMMITMENT	UFSAR SUPPLEMENT LOCATION (LRA APP. A)	ENHANCEMENT OR IMPLEMENTATION SCHEDULE	SOURCE
	(3) The inspection of 100% of the sandbed region epoxy coating every 10 years during the period of extended operation. Inspections will be staggered such that at least three bays will be examined every other refueling outage. (4) The inspection of all 20 torus bays at a frequency of every other refueling outage for the current coating system. Should the current coating system be replaced, the inspection frequency and scope will be re-evaluated. Inspection scope will, as a minimum, meet the requirements of ASME Section XI, Subsection IWE. Note: The scope and frequency for the inspections described in Item 4 (above) has been changed to all 10 bays every other refueling outage, in accordance with Item 21 of the IWE Inspection Program.			
34) Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental	Program is new. The program will be used to manage aging of non-EQ cables and connections during the period of extended operation. A representative sample of accessible cables and connections located in adverse localized environments will be visually inspected	A.1.34	Prior to the period of extended operation.	Section B.1.34

Subsection IWE Excerpts

SUBSECTION IWE
REQUIREMENTS FOR CLASS MC AND METALLIC LINERS OF CLASS CC COMPONENTS OF LIGHT-WATER COOLED PLANTS

Figures

Tables

ARTICLE IWE-1000
SCOPE AND RESPONSIBILITY

IWE-1100 SCOPE

This Subsection provides the rules and requirements for inservice inspection, repair, and replacement of Class MC pressure retaining components and their integral attachments, and of metallic shell and penetration liners of Class CC pressure retaining components and their integral attachments in light-water cooled plants.

IWE-1200 COMPONENTS SUBJECT TO EXAMINATION

IWE-1210 EXAMINATION REQUIREMENTS

The examination requirements of this Subsection shall apply to Class MC pressure retaining components and their integral attachments and to metallic shell and penetration liners of Class CC pressure retaining components and their integral attachments. These examinations shall apply to surface areas, including welds and base metal.

IWE-1220 COMPONENTS EXEMPTED FROM EXAMINATION

The following components (or parts of components) are exempted from the examination requirements of IWE-2000:

(a) vessels, parts, and appurtenances that are outside the boundaries of the containment as defined in the Design Specifications;

(b) embedded or inaccessible portions of containment vessels, parts, and appurtenances that met the requirements of the original Construction Code;

(c) portions of containment vessels, parts, and appurtenances that become embedded or inaccessible as a result of vessel repair or replacement if the conditions of IWE-1232 and IWE-5220 are met;

(d) piping, pumps, and valves that are part of the containment system, or which penetrate or are attached to the containment vessel. These components shall be examined in accordance with the rules of IWB or IWC, as appropriate to the classification defined by the Design Specifications.

IWE-1230 ACCESSIBILITY FOR EXAMINATION

IWE-1231 Accessible Surface Areas

(a) As a minimum, the following portions of Class MC containment vessels, parts, and appurtenances and Class CC metallic shell and penetration liners shall remain accessible for either direct or remote visual examination, from at least one side of the vessel, for the life of the plant:

(1) openings and penetrations;

(2) structural discontinuities;

(3) single-welded butt joints from the weld side;

(4) 80% of the surface area defined in Table IWE-2500-1, Examination Category E-A; and

(5) surface areas identified in IWE-1240.

(b) The requirements of IWE-1232 shall be met when accessibility for visual examination is not from the outside surface.

IWE-1232 Inaccessible Surface Areas

(a) Portions of Class MC containment vessels, parts, and appurtenances that are embedded in concrete or otherwise made inaccessible during construction of the vessel or as a result of vessel repair, modification, or replacement are exempted from examination, provided:

(1) no openings or penetrations are embedded in the concrete;

(2) all welded joints that are inaccessible for examination are double buttwelded and are fully radiographed and, prior to being covered, are tested for leak tightness using a gas medium test, such as Halide Leak Detector Test;

(3) all weld joints that are not double butt welded remain accessible for examination from the weld side; and

(4) the vessel is leak rate tested after completion of construction, repair, or replacement to the leak rate requirements of the Design Specifications.

(b) Portions of Class CC metallic shell and penetration liners that are embedded in concrete or otherwise made inaccessible during construction or as a result of repair or replacement are exempted from examination, provided:

(1) all welded joints that are inaccessible for examination are examined in accordance with CC-5520 and, prior to being covered or otherwise obstructed by adjacent structures, components, parts, or appurtenances, are tested for leak tightness in accordance with CC-5536; and

(2) the containment is leak rate tested after completion of construction, repair, or replacement to the leak rate requirements of the Design Specifications.

IWE-1240 SURFACE AREAS REQUIRING AUGMENTED EXAMINATION

IWE-1241 Examination Surface Areas

Surface areas likely to experience accelerated degradation and aging require the augmented examinations identified in Table IWE-2500-1, Examination Category E-C. Such areas include the following:

(a) interior and exterior containment surface areas that are subject to accelerated corrosion with no or minimal corrosion allowance or areas where the absence or repeated loss of protective coatings has resulted in substantial corrosion and pitting. Typical locations of such areas are those exposed to standing water, repeated wetting and drying, persistent leakage, and those with geometries that permit water accumulation, condensation, and microbiological attack. Such areas may include penetration sleeves, surfaces wetted during refueling, concrete-to-steel shell or liner interfaces, embedment zones, leak chase channels, drain areas, or sump liners.

(b) interior and exterior containment surface areas that are subject to excessive wear from abrasion or erosion that causes a loss of protective coatings, deformation, or material loss. Typical locations of such areas are those subject to substantial traffic, sliding pads or supports, pins or clevises, shear lugs, seismic restraints, surfaces exposed to water jets from testing operations or safety relief valve discharges, and areas that experience wear from frequent vibrations.

IWE-1242 Identification of Examination Surface Areas

Surface areas requiring augmented examination shall be determined in accordance with IWE-1241, and shall be identified in the Owner's Inspection Program.

Examination methods shall be in accordance with IWE-2500(c).

ARTICLE IWE-2000
EXAMINATION AND INSPECTION

IWE-2200 PRESERVICE EXAMINATION

(a) Examinations listed in Table IWE-2500-1 shall be completed prior to initial plant startup. These preservice examinations shall include the pressure retaining portions of components not exempted by IWE-1220.

(b) When visual examinations are required, these examinations shall be performed in accordance with IWE-2600, following the completion of the pressure test required by the Construction Code and after application of protective coatings (e.g., paint) when such coatings are required.

(c) When surface examinations are required by Table IWE-2500-1, shop or field examinations in accordance with NE-5000 for Class MC or CC-5500 for Class CC may serve in lieu of the on-site preservice examinations, provided:

(1) the examinations are conducted by the same method with equipment and techniques equivalent to those that are expected to be employed for subsequent inservice examinations;

(2) the shop or field examination records are, or can be, documented and identified in a form consistent with those required in IWA-6000; and

(3) the examinations are performed after the pressure test required by the Construction Code has been completed.

(d) When a vessel, liner, or a portion thereof is repaired or replaced during the service lifetime of a plant, the preservice examination requirements for the vessel repair or replacement shall be met.

(1) When the repair or replacement is performed while the plant is not in service, the preservice examination shall be performed prior to the resumption of service.

(2) When the repair or replacement is performed while the plant is in service, the preservice examination may be deferred to the next scheduled plant outage, provided nondestructive examination in accordance with the approved repair program is performed.

(3) When a system leakage test is required by IWE-5220, the preservice examination may be performed either prior to or following the test.

(e) Welds made as part of a repair or a replacement program shall be examined in accordance with the requirements of IWA-4000, except that for welds joining Class MC or Class CC components to items designed, constructed, and installed to the requirements of Section III, Class 1, 2, or 3, the examination requirements of IWB-2000, IWC-2000, or IWD-2000, as applicable, shall apply.

(f) Preservice examination for a repair or replacement may be conducted prior to installation provided:

(1) the examination is performed after the pressure test required by the Construction Code has been completed;

(2) the examination is conducted under conditions and with equipment and techniques equivalent to those that are expected to be employed for subsequent inservice examinations; and

(3) the shop or field examination records are, or can be, documented and identified in a form consistent with that required by IWA-6000.

(g) When paint or coatings are reapplied, the condition of the new paint or coating shall be documented in the preservice examination records.

IWE-2400 INSPECTION SCHEDULE

IWE-2410 INSPECTION PROGRAM

Inservice examinations and system pressure tests may be performed during plant outages such as refueling shutdowns or maintenance shutdowns. The requirements of either Inspection Program A or Inspection Program B shall be met.

IWE-2411 Inspection Program A

(a) With the exception of the examinations that may be deferred until the end of an inspection interval, as

TABLE IWE-2411-1
INSPECTION PROGRAM A

Inspection Interval	Inspection Period, Calendar Years of Plant Service	Minimum Examinations Completed, %	Maximum Examinations Credited, %
1st	3	100	100
2nd	7	33	67
	10	100	100
3rd	13	16	34
	17	40	50
	20	66	75
	23	100	100
4th	27	8	16
	30	25	34
	33	50	67
	37	75	100
	40	100	. . .

specified in Table IWE-2500-1, the required examinations shall be completed during each successive inspection interval, in accordance with Table IWE-2411-1. Following completion of Program A after 40 years, successive inspection intervals shall follow the 10 year inspection interval of Program B.

(b) The inspection period specified in IWE-2411(a) may be decreased or extended by as much as 1 year to enable an inspection to coincide with a plant outage, within the limitations of IWA-2430(c).

IWE-2412 Inspection Program B

(a) With the exception of the examinations that may be deferred until the end of an inspection interval, as specified in Table IWE-2500-1, the required examinations shall be completed during each successive inspection interval, in accordance with Table IWE-2412-1.

(b) The inspection period specified in IWE-2412(a) may be decreased or extended by as much as 1 year to enable an inspection to coincide with a plant outage, within the limitations of IWA-2430(d).

IWE-2420 SUCCESSIVE INSPECTIONS

(a) The sequence of component examinations established during the first inspection interval shall be repeated during each successive inspection interval, to the extent practical.

(b) When component examination results require evaluation of flaws, areas of degradation, or repairs in

TABLE IWE-2412-1
INSPECTION PROGRAM B

Inspection Interval	Inspection Period, Calendar Years of Plant Service, Within the Interval	Minimum Examinations Completed, %	Maximum Examinations Credited, %
1st	3	16	34
	7	50	67
	10	100	100
Successive	3	16	34
	7	50	67
	10	100	100

accordance with IWE-3000, 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 listed in the schedule of the inspection program of IWE-2411 or IWE-2412, in accordance with Table IWE-2500-1, Examination Category E-C.

(c) When the reexaminations required by IWE-2420(b) reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods, the areas containing such flaws, degradation, or repairs no longer require augmented examination in accordance with Table IWE-2500-1, Examination Category E-C.

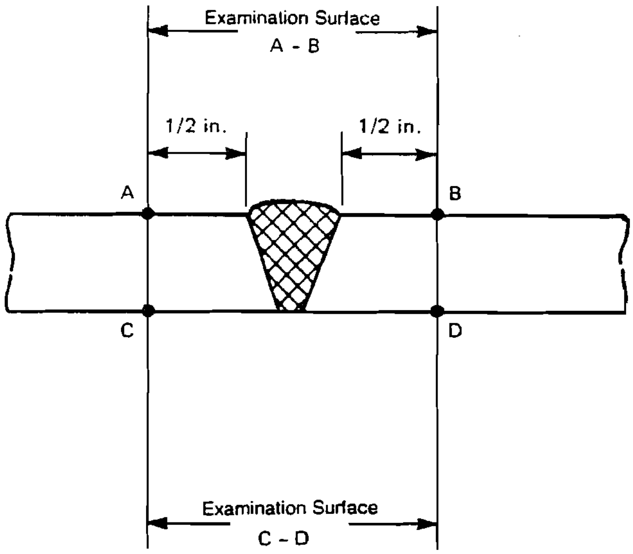
IWE-2430 ADDITIONAL EXAMINATIONS

(a) Examinations performed during any one inspection that reveal flaws or areas of degradation exceeding the acceptance standards of Table IWE-3410-1 shall be extended to include an additional number of examinations within the same category approximately equal to the initial number of examinations during the inspection.

(b) When additional flaws or areas of degradation that exceed the acceptance standards of Table IWE-3410-1 are revealed, all of the remaining examinations within the same category shall be performed to the extent specified in Table IWE-2500-1 for the inspection interval.

IWE-2500 EXAMINATION AND PRESSURE TEST REQUIREMENTS

(a) The method of examination for the components, parts, and items (e.g., seals, gaskets, and bolts) of the pressure retaining boundaries shall comply with those



Surface Areas A - B and C - D

FIG. IWE-2500-1 DISSIMILAR METAL WELDS

tabulated in Table IWE-2500-1, except where alternate examination methods are used that meet the requirements of IWA-2240.

(b) When paint or coatings are to be removed, the paint or coatings shall be visually examined in accordance with Table IWE-2500-1 prior to removal.

(c) Examination methods for surface areas for augmented examination in IWE-1242 shall comply with the following criteria.

(1) Surface areas accessible from both sides shall be visually examined using a VT-1 visual examination method.

(2) Surface areas accessible from one side only shall be examined for wall thinning using an ultrasonic thickness measurement method in accordance with Section V, T-544.

(3) When ultrasonic thickness measurements are performed, one foot square grids shall be used. The number and location of the grids shall be determined by the Owner.

(4) Ultrasonic measurements shall be used to determine the minimum wall thickness within each grid. The location of the minimum wall thickness shall be marked such that periodic reexamination of that location can be performed in accordance with the requirements of Table IWE-2500-1, Examination Category E-C.

IWE-2600 CONDITION OF SURFACE TO BE EXAMINED

(a) When a containment vessel or liner is painted or coated to protect surfaces from corrosion, preservice and inservice visual examinations shall be performed without the removal of the paint or coating.

(b) When removal of paint or coating is required, it shall be removed in a manner that will not reduce the base metal or weld thickness below the design thickness. Reapplied paint and coating systems shall be compatible with the existing system, and shall be examined in accordance with IWE-2200(g).

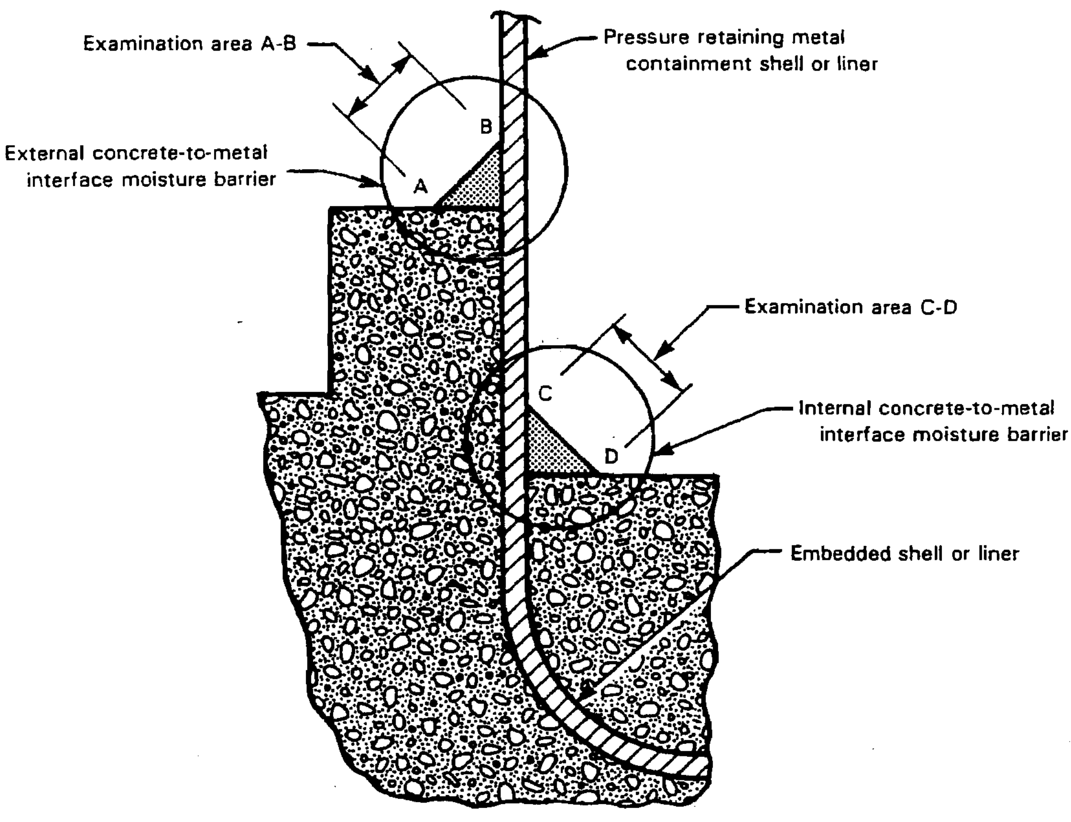


FIG. IWE-2500-2 EXAMINATION AREAS FOR MOISTURE BARRIERS

TABLE IWE-2500-1 (CONT'D)
EXAMINATION CATEGORIES

EXAMINATION CATEGORY E-A, CONTAINMENT SURFACES							
					Extent and Frequency of Examination		
Item No.	Parts Examined	Examination[1] Requirements/ Fig. No.	Examination Method	Acceptance Standard	1st Inspection Interval	Successive Inspection Intervals	Deferral of Inspection to End of Interval[9]
E1.10	Containment Vessel Pressure Retaining Boundary						
E1.11	Accessible Surface Areas[2,3,5]	IWE-3510.1	General Visual[7]	IWE-3510.1	100% Prior to each Type A test[8]	100% Prior to each Type A test[8]	Not permissible
E1.12	Accessible Surface Areas[2,4,5]	IWE-3510.2 IWE-3510.3	Visual, VT-3	IWE-3510.2 IWE-3510.3	100% End of interval	100% End of interval	N/A
E1.20	Vent System Accessible Surface Areas[2,4,5,6]	IWE-3510.2 IWE-3510.3	Visual, VT-3	IWE-3510.2 IWE-3510.3	100% End of interval	100% End of interval	N/A

NOTES:
(1) Examination may be made from either the inside or outside surface.
(2) Examination shall include structures that are parts of reinforcing structure, such as stiffening rings, manhole frames, and reinforcement around openings.
(3) Not including surface areas that are submerged or insulated.
(4) Including the wetted surfaces of submerged areas and the portions of insulated surface areas that are necessary to meet the requirements of IWE-1231(a)(4).
(5) Examination shall include the attachment welds between structural attachments and the pressure retaining boundary or reinforcing structure, except for nonstructural and temporary attachments as defined in NE-4435 and minor permanent attachments as defined in CC-4543.4. Examination shall include the weld metal and the base metal for $\frac{1}{2}$ in. beyond the edge of the weld.
(6) Includes flow channeling devices within containment vessels.
(7) Refer to IWE-3510.1 for General Visual examination method requirements.
(8) Refer to IWE-5220 for test requirements.
(9) Deferral of inspection is not permissible in the 4th and successive inspection intervals.

TABLE IWE-2500-1 (CONT'D)
EXAMINATION CATEGORIES

EXAMINATION CATEGORY E-B, PRESSURE RETAINING WELDS

Item No.	Parts Examined	Examination Requirements/ Fig. No.	Examination Method	Acceptance Standard	Extent and Frequency of Examination: 1st Inspection Interval	Extent and Frequency of Examination: Successive Inspection Intervals[4]	Deferral of Inspection to End of Interval[7]
E3.10	Containment Penetration Welds[3,5]		Visual, VT-1	IWE-3511	25% of the total number of welds[1,2]	25% of the total number of welds[1,2]	Permissible
E3.11	Longitudinal						
E3.12	Circumferential						
E3.13	Flued Head and Bellows Seal Circumferential Welds Joined to the Penetration						
E3.20	Flange Welds (Category C)[6]		Visual, VT-1	IWE-3511	25% of the total number of welds[1,2]	25% of the total number of welds[1,2]	Permissible
E3.30	Nozzle-to-Shell Welds (Category D)[6]		Visual, VT-1	IWE-3511	25% of the total number of welds[1,2]	25% of the total number of welds[1,2]	Permissible

NOTES:
(1) Examination shall include the weld metal and the base metal for ½ in. beyond the edge of the weld.
(2) Welds shall be randomly selected throughout the containment and representative of the type of welds described by each item number.
(3) Examination shall include welds made in accordance with Section III, Class MC, including those Class MC welds shown in Figs. NE-1120-1 and NE-1132-1.
(4) Different welds shall be selected for examination each inspection interval.
(5) Includes only those welds subject to cyclic loads and thermal stress during normal plant operation.
(6) Welded joint categories are as defined in NE-3351 for Class MC and CC-3840 for Class CC.
(7) Deferral of inspection is not permissible in the 4th and successive inspection intervals.

TABLE IWE-2500-1 (CONT'D) EXAMINATION CATEGORIES

EXAMINATION CATEGORY E-C, CONTAINMENT SURFACES REQUIRING AUGMENTED EXAMINATION

Item No.	Parts Examined	Examination Requirements/ Fig. No.	Examination Method	Acceptance Standard	Extent and Frequency of Examination: 1st Inspection Interval	Extent and Frequency of Examination: Successive Inspection Intervals	Deferral of Inspection to End of Interval[3]
E4.10	Containment Surface Areas						
E4.11	Visible Surfaces		Visual, VT-1	IWE-3512.1 IWE-3512.2	100% of Surface Areas Identified by IWE-1242[1]	100% of Surface Areas Identified by IWE-1242[2]	Not Permissible
E4.12	Surface Area Grid, Minimum Wall Thickness Location		Volumetric	IWE-3512.3	100% of Minimum Wall Thickness Locations during each Inspection Period, established in accordance with IWE-2500(c)(3)[2] and IWE-2500(c)(4)[2]	100% of Minimum Wall Thickness Locations during each Inspection Period, established in accordance with IWE-2500(c)(3)[2] and IWE-2500(c)(4)[2]	Not Permissible

NOTES:

(1) Containment surface areas requiring augmented examination are those identified in IWE-1240.

(2) The extent of examination shall be 100% for each inspection period until the areas examined remain essentially unchanged for three consecutive inspection periods. Such areas no longer require augmented examination in accordance with IWE-2420(c).

(3) Deferral of inspection is not permissible in the 4th and successive inspection intervals.

TABLE IWE-2500-1 (CONT'D)
EXAMINATION CATEGORIES

EXAMINATION CATEGORY E-D, SEALS, GASKETS, AND MOISTURE BARRIERS

Item No.	Parts Examined[1]	Examination Requirements/ Fig. No.	Examination Method	Acceptance Standard	Extent and Frequency of Examination: 1st Inspection Interval	Extent and Frequency of Examination: Successive Inspection Intervals	Deferral of Inspection to End of Interval[5]
E5.10	Seals[1]		Visual, VT-3	IWE-3513	100% of each item	100% of each item	Not permissible
E5.20	Gaskets[1]		Visual, VT-3	IWE-3513	100% of each item	100% of each item	Not permissible
E5.30	Moisture Barriers[2,3,4]	IWE-2500-2	Visual, VT-3	IWE-3513	100% of each item	100% of each item	Not permissible

NOTE:
(1) Examination shall include seals and gaskets on airlocks, hatches, and other devices that are required to assure containment leak-tight integrity.
(2) Examination shall include internal and external containment moisture barrier materials at concrete-to-metal interfaces intended to prevent intrusion of moisture against the pressure retaining metal containment shell or liner.
(3) Containment moisture barrier materials include caulking, flashing, and other sealants used for this application.
(4) Examination shall include all accessible surfaces of internal and external containment moisture barriers.
(5) Deferral of inspection is not permissible in the 4th and successive inspection intervals.

ARTICLE IWE-3000
ACCEPTANCE STANDARDS

IWE-3100 EVALUATION OF NONDESTRUCTIVE EXAMINATION RESULTS

IWE-3110 PRESERVICE EXAMINATIONS

IWE-3111 General

The preservice examination required by IWE-2200 and performed in accordance with the procedures of IWA-2200 shall be evaluated by the acceptance standards specified in Table IWE-3410-1. Acceptance of components for service shall be in accordance with IWE-3112, IWE-3114, and IWE-3115.

IWE-3112 Acceptance

(a) Components whose examination either confirms the absence of or reveals flaws or areas of degradation that do not exceed the acceptance standards of Table IWE-3410-1 shall be acceptable for service, provided the flaws or areas of degradation are recorded in accordance with the requirements of IWA-1400(h) and IWA-6220 in terms of location, size, shape, orientation, and distribution within the component.

(b) Components whose examination reveals flaws or areas of degradation that do not meet the acceptance standards of Table IWE-3410-1 shall be unacceptable for service unless such flaws or areas of degradation are removed or repaired, to the extent necessary to meet the acceptance standards, prior to placement of the component in service.

IWE-3114 Repairs and Reexaminations

Repairs and reexaminations shall comply with the requirements of IWA-4000. Reexamination shall be conducted in accordance with the requirements of IWA-2200; the recorded results shall demonstrate that the repair meets the acceptance standards specified in Table IWE-3410-1.

IWE-3115 Review by Authorities

(a) The repair program and the examination results shall be subject to review by the enforcement authorities having jurisdiction at the plant site.

(b) Evaluation of examination results may be subject to review by the regulatory authority having jurisdiction at the plant site.

IWE-3120 INSERVICE NONDESTRUCTIVE EXAMINATIONS

IWE-3121 General

Inservice nondestructive examination results shall be compared with recorded results of the preservice examination and prior inservice examinations. Acceptance of the components for continued service shall be in accordance with IWE-3122, IWE-3124, and IWE-3125.

IWE-3122 Acceptance

IWE-3122.1 Acceptance by Examination. Components whose examination results meet the acceptance standards listed in Table IWE-2500-1 shall be acceptable for continued service. Verified changes of flaws or areas of degradation from prior examinations shall be recorded in accordance with IWA-1400(h) and IWA-6220. Components that do not meet the acceptance standards of IWE-3000 shall be corrected in accordance with the provisions shown in IWE-3122.2, IWE-3122.3, or IWE-3122.4.

IWE-3122.2 Acceptance by Repair. Components whose examination results reveal flaws or areas of degradation that do not meet the acceptance standards listed in Table IWE-2500-1 shall be unacceptable for continued service until the additional examination requirements of IWE-2430 are satisfied, and the flaw or area of degradation is either removed by mechanical methods or the component repaired to the extent necessary to meet the acceptance standards of IWE-3000.

IWE-3122.3 Acceptance by Replacement. As an alternative to the repair requirement of IWE-3122.2, the component or the portion of the component containing the flaw or area of degradation shall be replaced in accordance with IWE-7000.

IWE-3122.4 Acceptance by Evaluation

(a) Components whose examination results reveal flaws or areas of degradation that do not meet the acceptance standards listed in Table IWE-3410-1 shall be acceptable for service without the removal or repair of the flaw or area of degradation or replacement 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. When supplemental examinations of IWE-3200 are required, if either the thickness of the base metal is reduced by no more than 10% of the nominal plate thickness or the reduced thickness can be shown by analysis to satisfy the requirements of the Design Specifications, the component shall be acceptable by evaluation.

(b) When flaws or areas of degradation are accepted by engineering evaluation, the area containing the flaw or degradation shall be reexamined in accordance with IWE-2420(b) and (c).

(c) When portions of later editions of the Construction Code or Section III are used, all related portions shall be met. The engineering evaluation shall be subject to review by the enforcement and regulatory authorities having jurisdiction at the plant site.

IWE-3124 Repairs and Reexaminations

Repairs and reexaminations shall comply with the requirements of IWA-4000. Reexaminations shall be conducted in accordance with the requirements of IWA-2200 and the recorded results shall demonstrate that the repair meets the acceptance standards of Table IWE-3410-1.

IWE-3125 Review by Authorities

The repair program and the reexamination results shall be subject to review by the enforcement authorities having jurisdiction at the plant site.

IWE-3130 INSERVICE VISUAL EXAMINATIONS

Components, whose visual examination as specified in Table IWE-2500-1 reveals areas that are suspect, shall be unacceptable for continued service unless, following verification of the suspect areas by the supplemental examination as required by IWE-3200, the requirements of IWE-3120 are satisfied.

IWE-3200 SUPPLEMENTAL EXAMINATIONS

Examinations that detect flaws or evidence of degradation that require evaluation in accordance with the requirements of IWE-3100 may be supplemented by other examination methods and techniques (IWA-2240) to determine the character of the flaw (i.e., size, shape, and orientation) or degradation. Visual examinations that detect surface flaws or areas that are suspect shall be supplemented by either surface or volumetric examination.

IWE-3400 STANDARDS

IWE-3410 ACCEPTANCE STANDARDS

The acceptance standards of Table IWE-3410-1 shall be applied to evaluate the acceptability of the component for service following the preservice examination and each inservice examination.

IWE-3430 ACCEPTABILITY

Flaws or areas of degradation that do not exceed the allowable acceptance standards of IWE-3500 for the respective examination category shall be acceptable.

IWE-3500 ACCEPTANCE STANDARDS

IWE-3510 STANDARDS FOR EXAMINATION CATEGORY E-A, CONTAINMENT SURFACES

IWE-3510.1 Visual Examinations — General

(a) The General Visual Examination shall be performed by, or under the direction of, a Registered Professional Engineer or other individual, knowledgeable in the requirements for design, inservice inspection, and testing of Class MC and metallic liners of Class CC components. The examination shall be performed either directly or remotely, by an examiner with visual acuity sufficient to detect evidence of degradation that may affect either the containment structural integrity or leak tightness.

(b) Prior to proceeding with a Type A test, conditions that may affect containment structural integrity or

TABLE IWE-3410-1
ACCEPTANCE STANDARDS

Examination Category	Component and Part Examined	Acceptance Standard
E-A	Containment surfaces	IWE-3510
E-B	Pressure retaining welds	IWE-3511
E-C	Containment surfaces requiring augmented examination	IWE-3512
E-D	Seals, gaskets, and moisture barriers	IWE-3513
E-F	Pressure retaining dissimilar metal welds	IWE-3514
E-G	Pressure retaining bolting	IWE-3515
E-P	All pressure retaining components	10 CFR 50, Appendix J

leak tightness shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.

IWE-3510.2 VT-3 Visual Examinations on Coated Areas. The inspected area, when painted or coated, shall be examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

IWE-3510.3 VT-3 Visual Examinations on Noncoated Areas. The inspected area shall be examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

IWE-3511 Standards for Examination Category E-B, Pressure Retaining Welds

IWE-3511.1 VT-1 Visual Examinations on Coated Areas. The inspected area, when painted or coated, shall be examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

IWE-3511.2 VT-1 Visual Examinations on Noncoated Areas. The inspected area shall be examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

IWE-3512 Standards for Examination Category E-C, Containment Surfaces Requiring Augmented Examination

IWE-3512.1 VT-1 Visual Examinations on Coated Areas. The inspected area, when painted or coated, shall be examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

IWE-3512.2 VT-1 Visual Examinations on Noncoated Areas. The inspected area shall be examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities. Areas that are suspect shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

IWE-3512.3 Ultrasonic Examination. Containment vessel examinations that reveal 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 prior to the next examination, shall be documented. Such areas shall be accepted by engineering evaluation or corrected by repair or replacement in accordance with IWE-3122. Supplemental examinations in accordance with IWE-3200 shall be performed when specified as a result of the engineering evaluation.

IWE-3513 Standards for Examination Category E-D, Seals, Gaskets, and Moisture Barriers

IWE-3513.1 VT-3 Visual Examinations. Seals, gaskets, and moisture barriers shall be examined for wear, damage, erosion, tear, surface cracks, or other defects that may violate the leak-tight integrity. Defective items shall be repaired or replaced.

IWE-3514 Standards for Examination Category E-F, Pressure Retaining Dissimilar Metal Welds

IWE-3514.1 Surface Examinations. The acceptance standards of IWB-3514 shall apply within the examination boundary of Fig. IWE-2500-1.

IWE-3515 Standards for Examination Category E-G, Pressure Retaining Bolting

IWE-3515.1 Visual Examinations. Bolting materials shall be examined in accordance with the material specification for defects which may cause the bolted connection to violate either the leak-tight or structural integrity. Defective items shall be replaced.

IWE-3515.2 Bolt Torque or Bolt Tension. Either bolt torque or bolt tension shall be within the limits specified for the original design. If no limits have been specified, acceptable bolt torque or bolt tension limits shall be determined and utilized.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
AMERGEN ENERGY COMPANY, LLC	)	Docket No. 50-219-LR
	)	
(Oyster Creek Nuclear Generating Station)	)	

AFFIDAVIT OF HANSRAJ G. ASHAR

I, Hansraj G. Ashar, do declare under penalty of perjury that my statements in the foregoing testimony and my attached statement of professional qualifications are true and correct to the best of my knowledge and belief.

/Original signed by/
____
Hansraj G. Ashar

Executed at Rockville, MD
this 20th day of July, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
AMERGEN ENERGY COMPANY, LLC	)	Docket No. 50-219-LR
	)	
(Oyster Creek Nuclear Generating Station)	)	

AFFIDAVIT OF JAMES A. DAVIS, PH.D

I, James A. Davis, do hereby declare under penalty of perjury that my statements in the foregoing testimony and my attached statement of professional qualifications are true and correct to the best of my knowledge and belief.

/Original signed by/
James A. Davis, Ph. D

Executed at Rockville, MD
this 20th day of July, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
AMERGEN ENERGY COMPANY, LLC	)	Docket No. 50-219-LR
	)	
(Oyster Creek Nuclear Generating Station)	)	

AFFIDAVIT OF MARK HARTZMAN, PH. D

I, Mark Hartzman, do hereby declare under penalty of perjury that my statements in the foregoing testimony and my statement of professional qualifications are true and correct to the best of my knowledge and belief.

/Original signed by/

Mark Hartzman, Ph. D

Executed at Rockville, MD
this 20th day of July, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
AMERGEN ENERGY COMPANY, LLC	)	Docket No. 50-219-LR
	)	
(Oyster Creek Nuclear Generating Station)	)	

AFFIDAVIT OF TIMOTHY O'HARA

I, Timothy O'Hara, do hereby declare under penalty of perjury that my statements in the foregoing testimony and my statement of professional qualifications are true and correct to the best of my knowledge and belief.

/Original signed by/
____
Timothy O'Hara

Executed at Medford, NJ
this 20th day of July, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
AMERGEN ENERGY COMPANY, LLC	)	Docket No. 50-219-LR
	)	
(Oyster Creek Nuclear Generating Station)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of the "NRC STAFF INITIAL STATEMENT OF POSITION ON DRYWELL CONTENTION" , "NRC STAFF TESTIMONY OF HANSRAJ G. ASHAR, DR. JAMES A. DAVIS, DR. MARK HARTZMAN AND TIMOTHY O'HARA CONCERNING DRYWELL CONTENTION" , AFFIDAVITS of Hansraj G. Ashar, Mark Hartzman, James A. Davis and Timothy O'Hara in the above-captioned proceeding have been served on the following by electronic mail with copies by deposit in the NRC's internal mail system or as indicated by an asterisk, by electronic mail, with copies by U.S mail, first class, this 20th day of July, 2007.

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