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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	)	July 20, 2007
AmerGen Energy Company, LLC	)	
	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

AMERGEN ENERGY COMPANY, LLC
INITIAL STATEMENT OF POSITION

In accordance with 10 C.F.R. § 2.1207(a)(1) and the Atomic Safety and Licensing Board's ("Board") April 17, 2007 Memorandum and Order,[1] AmerGen Energy Company, LLC ("AmerGen") hereby submits its Initial Statement of Position ("Statement") on Citizens'[2] drywell contention. AmerGen's Statement is supported by the seven-part direct testimony and 24 exhibits submitted with this Statement. This Statement summarizes AmerGen's case-in-chief and demonstrates that Citizens' contention is without merit because AmerGen's Aging Management Program ("AMP") for the sand bed region of the Oyster Creek Nuclear Generating

[1] (Prehearing Conference Call Summary, Case Management Directives, and Final Scheduling Order) (unpublished).

[2] "Citizens" 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.

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Station ("OCNGS") drywell shell provides reasonable assurance that the drywell shell will continue to perform its intended functions throughout the period of extended operation.

I. INTRODUCTION

Citizens' contention, in sum, is that AmerGen's scheduled ultrasonic testing ("UT") frequency for the sand bed region of the drywell shell is insufficient to maintain an adequate margin of drywell shell thickness during the period of extended operation. This Statement, supported by the attached testimony and exhibits, demonstrates that the four-year frequency of sand bed region UT measurements (*i.e.*, every other refueling outage), provides reasonable assurance that adequate margin will be maintained throughout a renewed term of plant operation. Reasonable assurance lies at the heart of this proceeding and often times has been overlooked by Citizens. This case is not about past maintenance practices or current term operations. It is about whether there is *reasonable assurance* that the OCNGS drywell UT monitoring plan is adequate to maintain that structure's intended functions for an additional twenty years. Moreover, reasonable assurance under 10 C.F.R. § 54.29 does not require absolute certainty, but only a demonstration that the applicant's AMP is reasonable in light of the relevant circumstances. For the many reasons set forth below, the answer to this question is yes – there is such assurance.

Following this introductory section, Section II of this Statement presents the technical background necessary to understand why the admitted contention lacks substantive merit. Section III outlines the procedural history of this proceeding, emphasizing that the Board has precluded litigation on essentially all of Citizens' previously proffered claims, and has significantly limited the scope of the contention to be litigated. Section IV frames the admitted contention by identifying the narrow, technical issue that remains within the scope of the contention. Section V sets forth the applicable NRC legal standards governing this license renewal proceeding. Section VI provides a detailed roadmap of AmerGen's argument, based on expert witness testimony and exhibits that are appended to this Statement. Section VII provides AmerGen's conclusions.

II. TECHNICAL BACKGROUND

This section presents the technical background necessary to understand why the admitted contention lacks substantive merit. This technical background is supported by and discussed in greater detail in Part 1 of AmerGen's pre-filed testimony.

A. Physical Layout

The OCNGS drywell shell is a carbon steel pressure vessel in the shape of an inverted light bulb, with a spherical lower section and a cylindrical upper section located inside the Reactor Building.[3] The relevant functions of the drywell shell are to accommodate the pressures and temperatures resulting from the break of any enclosed pipe and to provide structural support to the components housed within.[4] Although the drywell shell is about 100' tall, the portion within the scope of this contention (the "sand bed region") covers less than four feet within the lower spherical portion, from elevation 8'11" to 12'3".[5] Applicant's Exhibits 4, 5 and 7 depict the drywell shell and show, in particular, the sand bed region.

The drywell shell emerges from being embedded in concrete on both sides at elevation 8'11", and continues to be embedded in concrete on the inside until approximately elevation 11'0" (beneath the torus vent headers) and elevation 12'3" (areas between the torus vent

3 Letter from Michael P. Gallagher to NRC Document Control Desk, "Submittal of Information to ACRS Plant License Renewal Subcommittee Related to AmerGen's Application for Renewed Operating License for Oyster Creek Generating Station (TAC No. MC7624)" at 3-1 (Dec. 8, 2006) (Applicant's Exhibit 3).

4 "AmerGen's Pre-filed Direct Testimony: Part 1, Introduction, Drywell Physical Structure, History, and Commitments" ("AmerGen Dir. Part 1") at A.8.

5 *Id.* at A.9.

headers).[6] The non-embedded external side of this region was designed and constructed with a sand bed to provide structural support to the drywell shell as it emerges from being embedded in concrete on both sides to being embedded only on the interior.[7] This sand was removed in the early 1990s as part of the corrective actions to prevent corrosion, discussed below.[8] Although now without sand, this region is still referred to as the sand bed region.

The floor of the sand bed region on the exterior of the drywell shell is located at approximately elevation 8'11" and is concrete.[9] Five drains, equally spaced around the drywell shell, are located within this concrete floor and are designed to drain any water that might reach the floor.[10] Water from these drains is conveyed via tubing to large plastic bottles located on the floor of the Torus Room.[11] The sand bed region of the shell is divided into ten "bays," each containing a torus vent header that connects the interior of the drywell to the torus.[12] The torus is a steel pressure vessel encircling the base of the drywell, which is partially filled with water to provide pressure suppression in the event of a loss-of-coolant accident.[13]

Above the sand bed region, the drywell shell approaches to within a few inches of the Reactor Building concrete shield wall.[14] A small expansion gap remains between the drywell shell and the concrete shield wall in the upper drywell region.[15] Above approximately elevation

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6 *Id.*

7 *Id.*

8 *Id.*; *see also id.* at A.23.

9 *Id.* at A.9.

10 *Id.* at A.10.

11 *Id.*

12 *Id.*; *see also* Applicant's Exhibit 6. The bays are designated only with odd numbers, from 1 through 19.

13 AmerGen Dir. Part 1, at A.11.

14 *Id.* at A.12.

15 *Id.*

71'6", the upper drywell shell transitions from a spherical to a cylindrical shape.[16] The reactor cavity is located above the drywell.[17] The reactor cavity is filled with water only during refueling outages or those other outages during which the reactor vessel must be opened.[18] The reactor cavity is not filled with water during every plant outage. Applicant's Exhibit 4 shows the general location of the refueling cavity, the drywell shell, and the concrete shield wall.

B. <u>OCNGS Identified and Arrested the Historical Corrosion in the Sand Bed Region</u>

In the 1980s, water was observed coming from the sand bed drains.[19] OCNGS confirmed that the source of the water was leakage through small cracks in the reactor cavity liner.[20] OCNGS only observed water from the sand bed drains during outages when the reactor cavity was filled with water.[21] The concrete trough and 2" drain pipe located beneath the refueling cavity bellows is designed to capture this water.[22] The amount of water, however, was greater than the capacity of the trough and drain pipe, the curb of the trough was damaged, and the trough drain was blocked.[23] Because of these defects, water instead flowed into the gap between the exterior of the drywell shell and the concrete shield wall, and down to the sand bed region where it wetted the sand.[24]

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16 *Id.*

17 *Id.* at A.13.

18 *Id.*

19 *Id.* at A.20. An overview of the historical corrosion problem can be found in Applicant's Exhibit 3.

20 AmerGen Dir. Part 1, at A.20.

21 *See id.*

22 *Id.*; *see also* AmerGen's Pre-filed Direct Testimony: Part 4, Sources of Water ("AmerGen Dir. Part 4") at A.5.

23 AmerGen Dir. Part 1, at A.20.

24 *See id.* at A.21; *see also* AmerGen Dir. Part 4, at A.5.

The five floor drains designed to remove any water that might reach the sand bed region did not all perform as designed because they also were clogged.[25] Further, the sand bed concrete floor in some bays was not finished, impeding drainage of the sand bed region.[26]

The presence of water and sand (acting to keep the water in contact with an uncoated drywell shell) caused corrosion of the exterior of the drywell shell prior to the implementation of corrective actions.[27] The corrosion was not, however, evenly distributed either among or within the ten bays.[28] In general, corrosion was greatest in the vicinity of the torus vent headers and not in the middle of the bay.[29] In addition, there was an air-water interface located near the top of the sand bed region, between approximately elevations 11' and 12', above which there was virtually no corrosion.[30] Citizens have referred to this area as the "bath tub ring" of corrosion.

For reference, the as-designed thickness of the drywell shell in the sand bed region was 1.154".[31] The uneven distribution of corrosion resulted in a maximum general average metal loss of about 0.35" in part of Bay 19.[32] Some bays exhibited almost no observable corrosion.[33]

Corrective actions initiated in the late 1980s and early 1990s to prevent additional corrosion of the exterior drywell shell in the sand bed region included:[34]

- clearing of the sand bed drains

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25 AmerGen Dir. Part 1, at A.20.

26 *See id.*

27 *Id.* at A.21.

28 *Id.* at A.22.

29 *Id.*

30 *Id.*

31 *Id.*

32 *Id.*

33 *Id.*

34 *Id.* at A.23

- boring ten access holes through the concrete shield wall to completely remove the sand
- manual cleaning of the exterior shell
- application of a multi-layer epoxy coating system on the drywell shell exterior in the sand bed region
- repair of the concrete floor located between the exterior surface of the drywell shell and the concrete shield wall in those bays that required repair
- application of epoxy caulk at the exterior drywell shell/concrete floor junction in the former sand bed region
- application of stainless steel tape and a strippable coating to the reactor cavity during refueling outages to seal cracks in the reactor cavity liner[35]
- repair of the leakage collection trough and clearing of the trough drain.

These corrective actions have protected the exterior of the drywell shell in the sand bed region from further corrosion. Accordingly, corrosion of the exterior of the drywell shell in the sand bed region has been arrested.[36]

C. Recent Monitoring Confirms That Corrosion Has Been Arrested

AmerGen collected data during the October 2006 refueling outage which demonstrate that the corrective actions identified above are effective at preventing water from reaching the sand bed region, and are protecting the drywell shell in the sand bed region.[37] Specifically, AmerGen's daily monitoring of the refueling trough drain and five sand bed drains confirmed that no water leaked to the sand bed region, and visual inspections of the sand bed in all ten bays confirmed the same.[38]

AmerGen also performed VT-1 (*i.e.*, visual) inspections of the multi-layered epoxy coating system in all ten bays in the sand bed region in accordance with American Society of

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[35] Metal tape and strippable coating were not applied during the 1994 and 1996 outages. *Id.* at A.23.

[36] *Id.* at A.24.

[37] *See* AmerGen Dir. Part 4, at A.9, A.10, A.11; AmerGen Pre-filed Direct Testimony: Part 5: The Epoxy Coating ("AmerGen Dir. Part 5") at A.11, A.23. Leakage from the reactor cavity can only occur during those outages in which the reactor cavity is filled with water. AmerGen Dir. Part 4, at A.6.

[38] AmerGen Dir. Part 4, at A.9, A.10, A.11; AmerGen Dir. Part 5, at A.11, A.23.

Mechanical Engineers ("ASME") Code Section XI, Subsection IWE. The VT-1-qualified inspectors did not identify *any* defects or deterioration of the epoxy coating system.[39] In fact, the inspections reported the coating system to be in excellent condition. These visual inspections confirm that corrosion of the external drywell shell in the sand bed region remains arrested.

During the 2006 outage, AmerGen also took internal and external UT measurements of the drywell shell in all ten bays in the sand bed region. In particular, it took internal measurements from the 19 "grids" that were previously measured during the 1992, 1994 and 1996 refueling outages and it took external measurements from approximately 100 single "points" throughout the ten bays, which were previously measured during the 1992 refueling outage.[40] A comparison of the averages of the grid data over time further confirms that corrosion in this area has been arrested.[41]

D. <u>AmerGen's Commitments Provide Reasonable Assurance That the Drywell Will Continue to Perform Its Intended Functions</u>

AmerGen's AMP must provide reasonable assurance that the effects of aging will be adequately managed so that the intended functions of the drywell will be maintained consistent with the current licensing basis ("CLB") for the period of extended operation.[42] As part of its AMP, AmerGen has committed to perform inspections of the drywell shell. A full list of the docketed commitments related to the AMP for the drywell shell is provided in Applicant's Exhibit 10,[43] and AmerGen's commitments to perform future actions related to sand bed region corrosion control are identified in Part 1 of AmerGen's direct testimony. These future actions

[39] AmerGen Dir. Part 5, at A.11, A.23.

[40] AmerGen Pre-filed Direct Testimony: Part 3, Available Margin ("AmerGen Dir. Part 3") at A.9, A.12, A.20.

[41] *Id.* at A.38.

[42] 10 C.F.R. §§ 54.29 and 54.21; *see* discussion in Section V, below.

[43] In some cases, these commitments already have been completed.

include visual inspections of the multi-layer epoxy coating system that protects the exterior of the drywell shell in all ten bays, every other refueling outage (*i.e.*, every four years).[44] These commitments also include UT measurements from internal grids and external points every other refueling outage.[45]

At the time the Board admitted this contention, it characterized AmerGen's commitment as performing UT tests prior to the period of extended operation, two refueling outages later, and thereafter at an appropriate frequency not to exceed 10-year intervals.[46] As shown in Applicant's Exhibit 10, AmerGen has since augmented its UT frequency commitment so that it will perform UT measurements during the refueling outage in 2008, and then every other refueling outage thereafter (*i.e.*, every four years), using the same internal grid locations and the more than 100 external "points" that it measured during the 2006 refueling outage.

III. PROCEDURAL HISTORY

Throughout this proceeding, Citizens have proffered a multitude of often repetitive contentions and attempted to use any method available to broaden the scope of this hearing. The Board, however, has consistently rejected Citizens' attempts to do so and has instead left only a single contention with an extremely narrow technical focus.

A. Citizens' Original Admitted Contention Was Narrow in Scope

The Board promptly rejected most of Citizens' original allegations in their Request for Hearing and Petition to Intervene ("Original Petition"), admitting only a very narrow portion of the proffered contention. With respect to the drywell, Citizens initially claimed that AmerGen should be:

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44 AmerGen Dir. Part 1, at A.27.

45 *Id.*

46 *AmerGen Energy Company, LLC* (Oyster Creek Nuclear Generating Station), LBP-06-22, 64 N.R.C. 229, 240 (2006) ("LBP-06-22").

> required to conduct an adequate number of confirmatory UT measurements using state of the art equipment at all levels of the drywell liner, including multiple measurements in the area formerly known as the 'sand bed region' . . . and that additional UT measurements be greatly expanded in areas not previously inspected. [sic][47]

In its February 27, 2006 ruling, the Board narrowed the scope of the admitted contention considerably, limiting the issues to be litigated to the issue of whether periodic UT measurements in the sand bed region should be required. The admitted contention alleged:

> AmerGen's License Renewal Application fails to establish an adequate aging management plan for the sand bed region of the drywell liner, because its corrosion management program fails to include periodic UT measurements in that region throughout the period of extended operation and, thus, 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.[48]

The Board excluded, as lacking adequate basis, Citizens' allegations that AmerGen's AMP for the upper drywell liner (*i.e.*, above the sand bed region) was deficient, because Citizens failed "to explain with specificity or support why AmerGen's corrosion management program for that region is inadequate."[49] The Board also excluded any allegations related to the scope of AmerGen's UT monitoring program in the sand bed region.[50] Finally, the Board excluded Citizens' attempt, in their December 19, 2005 Reply Brief, to add the embedded region of the drywell, below the sand bed region, to the scope of their contention.[51]

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47 Request for Hearing and Petition to Intervene at 3-4 (Nov. 14, 2005) (emphasis in original).

48 *AmerGen Energy Co., LLC* (Oyster Creek Nuclear Generating Station), LBP-06-07, 63 N.R.C. 188, 217 (2006) ("LBP-06-07"). Following Citizens' Original Petition, AmerGen committed to a one-time set of confirmatory UT measurements in the sand bed region prior to the period of extended operation. Letter from C. N. Swenson to NRC Document Control Desk, "Additional Commitments Associated with Application for Renewed Operating License – Oyster Creek Generating Station" at 3 (Dec. 9, 2005).

49 LBP-06-07, 63 N.R.C. at 217 n.27.

50 *Id.* at 217 n.28.

51 *Id.*

In the meantime, on February 7, 2006, Citizens submitted a motion to add two new contentions, or, in the alternative, to supplement the basis of their original contention.[52] This motion argued that purportedly new information, obtained from a conference call between the NRC Staff and the Nuclear Energy Institute License Renewal Task Force, supported two late-filed contentions: (1) that the entire drywell liner, including inaccessible areas, must be "monitored and evaluated for corrosion," and (2) that AmerGen should conduct a "root cause analysis of the corrosion problem and implement a verifiable program to eliminate water leakage onto the drywell liner."[53] On March 22, 2006, the Board found this proposed contention to be incurably late and substantively inadmissible, in part because "it fail[ed] to identify an alleged deficiency that is specific to Oyster Creek or its License Renewal Application."[54] Citizens filed a motion for reconsideration[55] of the Board's decision on these late-filed contentions, but the Board rejected that motion as entirely without merit.[56]

Next, Citizens filed two motions on May 5, 2006: a Motion to Apply Subpart G Procedures, alleging misconduct and a general lack of trustworthiness on the part of AmerGen and its parent company, Exelon, and a Motion to Compel Further Mandatory Disclosures, seeking disclosure of records relating to corrosion above the sand bed region. On June 5, 2006, the Board rejected Citizens' Motion to Apply Subpart G Procedures as "not tenable" and "plainly fail[ing] to satisfy the regulatory standards for a Subpart G hearing."[57] The next day, the Board

52 Motion for Leave to Add Contentions or Supplement the Basis of the Current Contention (Feb. 7, 2006).

53 *AmerGen Energy Co., LLC* (Oyster Creek Nuclear Generating Station), LBP-06-11, 63 N.R.C. 391 (2006) ("LBP-06-11").

54 *Id.* at 399.

55 Motion for Reconsideration of Motion to Add New Contentions or Supplement the Basis of the Current Contention and Leave to File Such a Motion (Apr. 6, 2006).

56 *See* Memorandum and Order (Denying NIRS Motion for Reconsideration) (unpublished) (Apr. 27, 2006).

57 Memorandum and Order (Denying NIRS Motion to Apply Subpart G Procedures) at 4 (June 5, 2006) (unpublished).

ruled Citizens' Motion to Compel Further Mandatory Disclosures to be moot when it dismissed Citizens' original contention.[58]

AmerGen's new commitment[59] to conduct periodic UT monitoring in the sand bed region had rendered Citizens' original contention moot.[60] In dismissing Citizens' original contention, however, the Board afforded Citizens a limited opportunity to seek leave to file a new contention related to AmerGen's periodic UT program.[61] The Board also granted Citizens' request to supplement the basis of their contention, after AmerGen docketed additional commitments on June 20, 2006.[62]

B. The Board Admitted Only One of Seven Allegations in Citizens' New Contention

Citizens, however, went far beyond the narrow window opened by the Board, and again attempted to shoehorn in a wide variety of unfounded and late allegations in their Petition to Add a New Contention,[63] and Supplement to Petition to Add a New Contention.[64] These allegations included: (1) the "acceptance criteria" for determining minimum required thicknesses were "inadequate to ensure adequate safety margins"; (2) the "scheduled UT monitoring frequency in the sand bed region" was "insufficient to maintain an adequate safety margin"; (3) the "monitoring in the sand bed region for moisture and coating integrity" was inadequate; (4) the

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[58] *AmerGen Energy Co., LLC* (Oyster Creek Nuclear Generating Station), LBP-06-16, 63 N.R.C. 737, 739 (2006) ("LBP-06-16").

[59] Letter from Michael P. Gallagher to NRC Document Control Desk, "Commitments Associated with Containment (Drywell and Torus) Condition Monitoring Related to AmerGen Application for Renewed Operating License – Oyster Creek Generating Station (TAC No. MC7624)" Encl. at 1 (Apr. 4, 2006).

[60] *See* AmerGen's Motions to Dismiss Drywell Contention as Moot and to Suspend Mandatory Disclosures (April 25, 2006).

[61] LBP-06-16, 63 N.R.C. at 739.

[62] Order (Granting NIRS's Motion for Leave to Submit a Supplement to Its Petition) (July 5, 2006) (unpublished).

[63] June 23, 2006 ("June 23 Petition").

[64] July 25, 2006 ("Supplement").

"response to wet conditions and coating failure in the sand bed region" was inadequate; (5) the "scope of UT monitoring" was insufficient; (6) the "quality assurance for the measurements in the sand bed region" was inadequate; and (7) the methods used for "analyzing UT results in the sand bed region" were "flawed."[65]

On October 10, 2006, the Board rejected six of the seven challenges Citizens presented, because they were incurably late, lacking in basis, or both.[66] The only exception was the second issue: the Board admitted Citizens' challenge to the adequacy of the UT monitoring frequency in the *sand bed region*.[67] The Board's ruling reaffirmed its previous orders in this proceeding in that the scope of Citizens' admitted contention is limited to the sand bed region, and thus issues related to the upper region and embedded region of the drywell are excluded from litigation.[68]

In rejecting *every* aspect of Citizens' reformulated contention except for the frequency of AmerGen's UT monitoring in the sand bed region, the Board ruled that "any challenge to the adequacy of AmerGen's acceptance criteria should have been made at the time Citizens filed their initial Petition to Intervene. It cannot be submitted at this late juncture."[69] Thus, Citizens may not challenge the origin, derivation or adequacy of AmerGen's acceptance criteria. To the extent that AmerGen demonstrates that its UT monitoring frequency is adequate to provide

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[65] Supplement at 7; LBP-06-22, 64 N.R.C. at 236.

[66] LBP-06-22, 64 N.R.C. at 240, 247-49, 251, 253, 255.

[67] *Id.* at 240.

[68] *Id.*; *see also* Memorandum and Order (Denying AmerGen's Motion for Summary Disposition) at 2 n.4 (June 19, 2007) (unpublished) ("June 19 Order"); LBP-06-07, 63 N.R.C. at 216 n.27 (limiting Citizens' original contention of omission to the sand bed region); LBP-06-16, 63 N.R.C. at 744 (allowing Citizens to file a new contention "raising a specific substantive challenge to AmerGen's new periodic UT program for the sand bed region" and directed that "the substance of [the new contention] must be limited to the sand bed region").

[69] LBP-06-22, 64 N.R.C. at 240; *see also* June 19 Order at 2 n.4 (confirming the exclusion of acceptance criteria derivation from the admitted contention). Therefore, AmerGen's acceptance criteria testimony in Part 2 is intended solely to provide background for the testimony on available margin in Part 3, since margin is determined by reference to the applicable acceptance criteria. That background is not open to challenge, with the narrow exception that Citizens may present an argument that the, "application of acceptance criteria and analytic methodology to the 2006 UT results was inconsistent with past practice." June 19 Order at 8.

reasonable assurance that those acceptance criteria will continue to be satisfied during the period of extended operation, it also will have demonstrated that the frequency of UT monitoring provides "an adequate safety margin," and answered the allegations in the contention.

The Board also rejected the five other challenges in Citizens' new petitions. All of the following issues are, therefore, excluded from further litigation:

- Any challenge to the adequacy of AmerGen's moisture monitoring program.[70] This includes AmerGen's Protective Coating Monitoring and Maintenance Program ("PCMMP"), AmerGen's plans for periodic visual inspections of the multi-layer epoxy coating system on the exterior of the sand bed region of the drywell and any challenges to the adequacy of AmerGen's commitments to identify water leakage and initiate corrective actions to address any leakage that might be discovered.[71]

- Any challenge to AmerGen's response to wet conditions and coating failure "effectively challenges" the adequacy of AmerGen's PCMMP, and that since "AmerGen has committed" to an ASME Section XI, Subsection IWE compliant program, "Citizens are prohibited from challenging its adequacy."[72]

- Any challenge to the spatial scope of AmerGen's UT monitoring regime because information regarding when and where UT measurements would be taken was available long before they submitted their new petition.[73]

- Any challenge to the adequacy of AmerGen's quality assurance program for UT measurements because "a licensee's quality assurance program is excluded from license renewal review" and "is outside the scope of this proceeding."[74]

[70] LBP-06-22, 64 N.R.C. at 247.

[71] *Id.* at 246.

[72] *Id.* at 245, 247; *see also* June 19 Order at 2 n.4.

[73] LBP-06-22, 64 N.R.C. at 249-51; *see also* June 19 Order at 2 n.4.

[74] LBP-06-22, 64 N.R.C. at 253; *see also* June 19 Order at 2 n.4.

- Any challenge to AmerGen's "statistical techniques" and methodology for determining a corrosion rate are inadmissible and outside the scope of the contention.[75]

C. The Board Has Continued to Reject Citizens' Repeated Efforts to Broaden the Scope of Litigation

Since the admission of their new contention, Citizens have followed with two additional attempts to add contentions. On December 20, 2006, they filed a motion to add two late-filed contentions.[76] The first proposed contention recycled previous allegations of potential corrosion in the embedded region of the drywell shell, below the sand bed region, and the second alleged a failure to address potential corrosion from the drywell shell interior. The Board rejected both of these proposed contentions, because they were untimely *and* substantively inadmissible.[77] On February 6, 2007, Citizens attempted yet again to recycle previously-rejected arguments when they submitted a fourth late-filed contention challenging the acceptance criteria for drywell shell thicknesses in the sand bed region.[78] The Board again rejected this proposed contention as incurably late.[79]

The Board's repeated rejections of Citizens' often duplicative late-filed contentions do not seem to have deterred Citizens' desire to reintroduce excluded issues into this proceeding. In their response to AmerGen's Motion for Summary Disposition, Citizens presented, and

75 LBP-06-22, 64 N.R.C. at 254-55; *see also* June 19 Order at 2 n.4. More specifically, Citizens are "foreclosed" from arguing "that the methods of calculation or uncertainties contained in AmerGen's Statistical Analysis are inadequate, or that AmerGen must consider additional uncertainties in performing its analysis." Memorandum and Order (Clarifying Memorandum and Order Denying AmerGen's Motion for Summary Disposition) at 4 (July 11, 2007) (unpublished) ("July 11 Order").

76 Motion for Leave to Add Contentions and Motion to Add Contentions (Dec. 20, 2006).

77 Memorandum and Order (Denying Citizens' Motion for Leave to Add Contentions and Motion to Add Contention) (Feb. 9, 2007) (unpublished).

78 Motion for Leave to Add a Contention and Motion to Add a Contention (Feb. 6, 2007).

79 Memorandum and Order (Denying Citizens' Motion for Leave to Add a Contention and Motion to Add a Contention) (Apr. 10, 2007) (unpublished).

AmerGen sought to strike, arguments related to at least three excluded issues: (1) the established acceptance criteria; (2) AmerGen's methods for analyzing UT results in the sand bed region; and (3) the spatial scope of AmerGen's UT monitoring program in the sand bed region.[80] Although the Board did not grant summary disposition, it granted the Motion to Strike on these issues and expressed the expectation that "the parties will scrupulously endeavor to remain within that scope as they prepare testimony for the evidentiary hearing."[81]

The parties requested clarification from the Board on two points in the June 19 Order. In response, the Board first reaffirmed that any challenge to AmerGen's UT monitoring program that applies prior to the period of extended operation "would constitute an attack on AmerGen's current licensing basis and is beyond the scope of this proceeding."[82] Second, although it identified a very narrow exception, the Board reiterated its "admonish[ment]" to Citizens not to raise yet another challenge to the "methods of calculation or uncertainties contained in AmerGen's Statistical Analysis" or to argue "that AmerGen must consider additional uncertainties in performing its analysis."[83]

IV. SUMMARY OF THE CONTENTION AS ADMITTED

The contention as admitted by the Board states:

> AmerGen's scheduled UT monitoring frequency in the sand bed region [during the period of extended operation] is insufficient to maintain an adequate safety margin. More precisely, this Board stated that the issue presented is whether, in light of the uncertainty regarding the existence <u>vel</u> <u>non</u> of a corrosive environment in the sand bed region . . . AmerGen's UT monitoring plan is sufficient to ensure adequate margins.[84]

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[80] Citizens' Answer Opposing AmerGen's Motion for Summary Disposition (Apr. 26, 2007) at 5, 8, 13.

[81] June 19 Order at 2.

[82] July 11 Order at 2.

[83] *Id.* at 4.

[84] June 19 Order at 2 (citations and internal quotations omitted); *see also* LBP-06-22, 64 N.R.C. at 236.

The admitted contention is, therefore, very limited in scope and focuses only on the sufficiency of the frequency of UT measurements of the sand bed region of the OCNGS drywell shell. The "foundation" of Citizens' argument is that "UT measurements must be taken at least annually because the historical corrosion rate has been such that, if corrosion were to resume at that rate, the safety margin would be eliminated within two years."[85] The only remaining litigable issues, as explained by the Board[86] are:

1. "the amount by which the remaining thickness of the shell exceeds the established acceptance criteria in the sand bed region";

2. "the 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 sand is no longer there to hold water in the previously corroded area of the shell"; and

3. "the corrosion rate – including the uncertainties related to its determination – that reasonably may be expected in the sand bed region."

AmerGen demonstrates in Section VI, below, that there is adequate margin remaining to provide reasonable assurance that any additional effects of aging on the drywell shell in the sand bed region will be adequately managed. Thus, the bases for Citizens' contention lack merit.

V. LEGAL STANDARDS

The standards governing the issuance of renewed licenses for operating commercial nuclear power plants are set forth in 10 C.F.R. §§ 54.21 and 54.29. 10 C.F.R. § 54.21 requires AmerGen to "demonstrate that the effects of aging will be *adequately managed* so that the

[85] LBP-06-22, 64 N.R.C. at 244 n.16.

[86] June 19 Order at 7.

[drywell] will be maintained consistent with the CLB for the period of extended operation."[87] 10 C.F.R. § 54.29 requires AmerGen to identify and take (or plan to take) actions to manage the effects of aging on the functionality of the drywell "such that there is *reasonable assurance* that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB . . . ."[88] Taken together, these regulations require AmerGen to establish an AMP that is adequate to provide reasonable assurance that the drywell will be maintained according to the CLB for an additional twenty years.

As the Commission has reaffirmed in the course of this proceeding, issues related to the OCNGS CLB are outside the scope of the license renewal process. "[R]eview of a license renewal application does not reopen issues relating to a plant's current licensing basis, or any other issues that are subject to routine and ongoing regulatory oversight and enforcement."[89]

Reasonable assurance under 10 C.F.R. § 54.29 does not require absolute certainty, but only a demonstration that the applicant's AMP is reasonable in light of the relevant circumstances. For example, in *North Anna Envtl. Coalition v. NRC*, an intervenor argued that a "reasonable assurance of safety" required proof beyond a reasonable doubt.[90] The U.S. Court of Appeals for the District of Columbia Circuit rejected this view: "[h]ad the regulations been intended to require proof beyond a reasonable doubt we believe it would have been clearly so stated."[91] Similarly, the Commission has also ruled that "'reasonable assurance' does not mean a

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87 10 C.F.R. § 54.21(a)(3) (emphasis added).

88 10 C.F.R. § 54.29(a) (emphasis added).

89 *AmerGen Energy Co., LLC* (Oyster Creek Nuclear Generating Station), CLI-06-24, 64 N.R.C. 111, 117-18 (2006); *see also* July 11 Order at 2 ("an attack on AmerGen's current licensing basis . . . is beyond the scope of this proceeding.").

90 533 F.2d 655, 667 (D.C. Cir. 1976).

91 *Id.*; *see also Crowther v. Seaborg*, 312 F. Supp. 1205, 1234 (D. Colo. 1970) (finding that a reasonable decision is one made "in light of the best of available scientific knowledge" and does not require "absolute certainty").

demonstration of near certainty. . . ."[92] In the license renewal context, AmerGen is not required to demonstrate that additional corrosion of the drywell is impossible.[93] Instead, AmerGen need only demonstrate that its AMP, in light of the known or likely circumstances, provides reasonable assurance that it will maintain the drywell in accordance with the CLB during the period of extended operation.

AmerGen has met the requirement to establish an AMP that provides reasonable assurance that the drywell will perform in accordance with the CLB during the period of extended operation. AmerGen has defined an AMP for the drywell with the express purpose of adequately managing age-related degradation. AmerGen's AMP for the drywell shell is based upon ASME Section XI, Subsection IWE for steel containments (Class MC), in accordance with the provisions of 10 C.F.R. § 50.55a.[94] Section XI, Subsection IWE is approved for use by the NRC in 10 C.F.R. § 50.55a and, therefore, is not subject to challenge in this proceeding.[95]

While Citizens' contention challenges only the frequency of AmerGen's planned UT of the sand bed region, that UT is only one *part* of AmerGen's overall AMP. Citizens' contention fails to account for the remainder of AmerGen's AMP. So long as AmerGen's AMP for managing corrosion in the sand bed region, taken as a whole, provides the requisite reasonable assurance, AmerGen satisfies the applicable requirements of 10 C.F.R. Part 54.

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92 *Public Service Co. of New Hampshire* (Seabrook Station, Units 1 & 2), CLI-78-1, 7 N.R.C. 1, 18 (1978); *see also* Disposal of High-Level Radioactive Wastes in a Proposed Geologic Repository at Yucca Mountain, Nevada, 66 Fed. Reg. 55,732, 55,739-40 (Nov. 2, 2001) (rejecting the view that use of "reasonable assurance" as a basis for judging compliance compels a focus on extreme values).

93 *See Florida Power & Light Co.* (Turkey Point Nuclear Generating Plant, Units 3 and 4), CLI-01-17, 54 N.R.C. 3, 4 (2001) ("Adverse aging effects generally are gradual and thus can be detected by programs that ensure *sufficient* inspections and testing.") (emphasis added); *c.f. Yankee Atomic Electric Co.* (Yankee Nuclear Power Station), CLI-96-7, 43 N.R.C. 235, 261-62 (1996) (rejecting intervenors' claim that owners' ability to pay decommissioning costs was "not ironclad").

94 LBP-06-22, 64 N.R.C. at 247.

95 *See id.*

VI. ARGUMENT

As demonstrated in AmerGen's pre-filed testimony and the supporting exhibits, the established frequency of UT measurements of the drywell shell in the sand bed region every four years (*i.e.*, every other refueling outage), provides reasonable assurance that the drywell shell will continue to perform its intended functions of structural support and pressure containment in accordance with applicable ASME Code requirements and the CLB during the planned license renewal period.

As discussed in Section IV of this Statement, the Board has identified three remaining litigable issues in this proceeding: (1) the amount by which the remaining thickness exceeds the established acceptance criteria; (2) the existence <u>vel</u> <u>non</u> of a corrosive environment; (3) the corrosion rate – including the uncertainties related to its determination – that reasonably may be expected. The direct testimony in support of AmerGen's argument on these three issues is set forth in seven parts. Part 1 provides an introduction and an overview of AmerGen's testimony, describes the physical drywell structure, the history of corrosion in the sand bed region, and AmerGen's regulatory commitments to prevent, identify and correct any possible future corrosion of the drywell shell in the sand bed region. Parts 2 and 3 of AmerGen's testimony directly address the first remaining litigable issue, by identifying the applicable acceptance criteria and discussing the current available margin as measured against those acceptance criteria. Parts 4 and 5 of AmerGen's testimony address the second remaining litigable issue, by discussing the potential for water to enter the sand bed region and the epoxy coating system on the exterior of the drywell shell. Part 6 of AmerGen's testimony addresses the third and final remaining litigable issue by discussing potential future corrosion rates during the period of extended operation. Part 7 provides AmerGen's conclusions.

Specifically, AmerGen's direct testimony demonstrates that: (1) the bounding average thickness of the drywell shell exceeds the established general buckling criterion by 0.064"; (2) the sources of water have been effectively eliminated and a corrosive environment no longer exists in the sand bed region; and (3) even very conservative assumptions about potential future corrosion rates during the period of extended operation do not call into question AmerGen's ability to continue to satisfy ASME code requirements. Accordingly, AmerGen's UT frequency provides reasonable assurance that, even if corrosion were to occur, it would be detected and corrected such that the drywell would continue to perform its intended functions. It should also be emphasized that AmerGen's regulatory commitments provide reasonable assurance that, if unanticipated conditions are found, the plant will not be restarted without a determination, subject to review and concurrence by the NRC Staff, that the applicable acceptance criteria are satisfied.

A. <u>The Remaining Thickness of the Drywell Shell Exceeds the Established Acceptance Criteria By At Least 0.064"</u>

Part 2 of AmerGen's direct testimony describes the sand bed region acceptance criteria that AmerGen has used to meet ASME code requirements and will use during the period of extended operation. OCNGS derived three relevant acceptance criteria for the drywell shell in the sand bed region from analyses performed by General Electric ("GE") in the 1990s. These criteria and their derivation are part of the OCNGS CLB and are not subject to challenge in this proceeding.

By way of background, the drywell shell in the sand bed region has two modes of potential failure which we will refer to as "buckling," caused by physical loads and stresses, and "pressure," caused by internal pressure. Logically, a large area of metal must corrode in order for the drywell shell at the OCNGS to no longer serve its physical support function. Therefore, buckling becomes an issue only when there is corrosion over a significant area of the shell. Also, logically, only a small area of metal must corrode for the shell to exceed its ability to retain internal pressures. For example, a very small hole in the shell would exceed the applicable ASME Code requirements for pressure, because any hole in the shell will allow internal air to escape. That same small hole, however, would have no effect on buckling.

The first acceptance criterion addresses the potential for buckling, and is a minimum general average thickness of 0.736". This is the "general buckling criterion." This criterion assumes the *entire* shell in the sand bed region has thinned to 0.736". An area of average thickness less than 0.736" remains adequate if it meets the second criterion, referred to as the "local buckling criterion," which is best described as a nine-square foot "tray" with a one square foot center averaging 0.536" and sides that taper back to 0.736" over an additional foot on each side.[96] Finally, the third criterion is a pressure criterion of 0.490", on average, in an area 2.5" in diameter.

As explained in Section IV.A, above, what these acceptance criteria are, and their adequacy, are beyond the scope of the admitted contention.[97]

As explained in Part 3 of AmerGen's direct testimony, the bounding average area of the drywell shell in the sand bed region has available margin of 0.064". This is based on the bounding general average thickness in the sand bed region of 0.800" from a UT data grid in Bay 19, which leaves a margin of 0.064" when compared to the 0.736" general area thickness criterion (*i.e.*, 0.800"-0.736"). All other average UT data collected from other grids demonstrate an available margin greater than 0.064". And comparison of individual UT data points collected from the exterior of the drywell shell against the local buckling criterion reveals that the general

96 *See* Applicant's Exhibit 11

97 LBP-06-22, 64 N.R.C. at 237-40.

buckling criterion applied in Bay 19, rather than the local buckling criterion, is the bounding scenario for buckling. Individual UT data points are also compared to the pressure criterion of 0.490". The thinnest external single point is 0.602" in Bay 13. This results in an available margin of 0.112", which is more than 0.064".

As explained in Section IV.A, above, challenges to AmerGen's "statistical techniques" are inadmissible and outside the scope of the contention.[98] Accordingly, Citizens may not challenge the "methods of calculation or uncertainties contained in AmerGen's Statistical Analysis" or argue that "that AmerGen must consider additional uncertainties in performing its analysis."[99]

B. <u>The Sources of Water Have Been Effectively Eliminated and a Corrosive Environment No Longer Exists In the Sand Bed Region</u>

As shown in Part 4 of AmerGen's direct testimony, there is reasonable assurance that corrosion of the external surface of the drywell shell in the sand bed region will remain arrested during the extended period of operation. The potential for continued corrosion of the external surface of the drywell shell in the sand bed region ceased following the 1992 refueling outage, when the sand removal was completed and the surface of the shell was coated with a multi-layer epoxy coating system. Corrosion requires the ongoing presence of water, exposed metal, and oxygen. The epoxy coating system prevents water and oxygen from coming into contact with the underlying carbon steel drywell shell, thereby preventing additional corrosion.

Part 4 also demonstrates that the potential sources of water are limited to refueling or other outages during which the reactor cavity is filled with water, because the only known source of water in the exterior sand bed region is the reactor cavity liner. The reactor cavity liner is

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98 LBP-06-22, 64 N.R.C. at 254-55; *see also* June 19 Order at 2 n.4.

99 July 11 Order at 4.

filled with water only during such outages. Moreover, the use of metal tape and strippable coating on the reactor cavity liner during such outages, in conjunction with repairs to and clearing of the concrete trough drain, has effectively eliminated the presence of water from the sand bed region. Observation of the exterior of the drywell shell in the sand bed region and the sand bed drains during the 2006 refueling outage confirms the effectiveness of this practice. During that outage, there was no water observed in the sand bed region nor any leakage observed from the sand bed drains.

Finally, Part 4 explains why condensation on the exterior drywell shell surface is not possible except during an outage when the drywell chillers are used. Even during such an outage, condensation is unlikely, and any moisture on the exterior of the drywell shell would quickly evaporate following the outage. The drywell chillers were used during the 2006 refueling outage and no condensation was observed on the exterior shell's surface.

As described in Part 5 of AmerGen's testimony, a robust, multi-layered epoxy coating system has been applied to the OCNGS exterior drywell shell in the sand bed region. This system is more than appropriate for this application, is currently in excellent condition, and will be subject to appropriate periodic visual testing ("VT-1") inspections to ensure its continued integrity. This epoxy coating system should preclude further corrosion of this region.

Thus, for corrosion to occur during the period of extended operation, this epoxy coating system—which was designed for underwater environments—would have to deteriorate. However, deterioration is not expected during the period of extended operation because none of the factors that would be most likely to contribute to deterioration of the coating—elevated temperature, high radiation, submersion in water, or ultraviolet light—is present. In fact, similar coating systems that have been in service for decades still do not exhibit signs of end-of-life deterioration.

Even if the epoxy coating system deteriorated to reveal the underlying carbon steel drywell shell during the period of extended operation, such deterioration would be detected and repaired. AmerGen has committed to repair any degraded coating.

As explained in Part 5, the individuals who performed the visual (*i.e.*, VT-1) inspections of this epoxy coating system in 2006, reported that it is in excellent condition. When the coating system nears its end-of-life, it will show signs of embrittlement and attendant cracking, and these changes will occur over a long period of time. Such deterioration would be visible during the VT-1 inspections which will be performed no less frequently than every fours years (*i.e.*, every other refueling outage) during the period of extended operation.

Part 5 also explains that the VT-1 inspections conducted at OCNGS would have disclosed even very small amounts of corrosion beneath the epoxy coating system if such corrosion was present. The corrosion products (iron oxides) seeping through very localized defects in the coating, such as Citizens' postulated "pinholes or holidays," would be visible during the VT-1 inspections from corrosion rates as low as 0.002" per year. More widespread corrosion beneath the epoxy coating system would also, of course, be detected during VT-1 inspections.

C. AmerGen's UT Frequency Provides Reasonable Assurance That, Should Corrosion Occur, It Would Be Detected and Corrected Such That the Drywell Shell Would Continue to Perform Its Intended Functions

As explained in Part 6 of AmerGen's direct testimony, there is no expected significant future corrosion of the exterior surface of the drywell shell based on the conditions anticipated during the license renewal term at OCNGS. Corrosion requires the ongoing presence of an exposed metal and dissolved oxygen in an electrolyte (*e.g.*, water). The exterior epoxy coating system is designed to preclude corrosion since it separates the metal surface of the drywell shell from water. In other words, corrosion of the external surface of the drywell shell has been arrested, and AmerGen's AMP is intended to maintain these conditions throughout the period of extended operation.

Based on extremely conservative assumptions, in the unlikely hypothetical scenario that: (1) pinholes or holidays exist in the epoxy coating system covering the exterior drywell shell; (2) water is present on the exterior drywell shell; (3) those pinholes or holidays allow oxygen and water to come into contact with the underlying metal shell; and (4) that under these conditions, corrosion would take place a rate of 0.017" per year (a rate last seen prior to the removal of sand from the sand bed region), corrosion would be limited to approximately 0.0014" every two years (*i.e.*, the time between the beginning of one refueling outage and the start of the next refueling outage). This corrosion would be very localized and the remaining thickness of the drywell shell, therefore, would be compared against the pressure or local buckling criteria. This would provide even more available margin than 0.064." Thus, there simply cannot be the amount of widespread corrosion required to exceed the existing average available margin of 0.064".

Accordingly, AmerGen's UT frequency of every four years provides more than reasonable assurance that the drywell shell in the sand bed region will continue to perform its intended functions of structural support and pressure containment in accordance with applicable ASME Code requirements and the CLB for the license renewal period.

VII. CONCLUSIONS

The scheduled frequency of UT measurements in the sand bed region provides reasonable assurance that the drywell shell will continue to perform its intended functions during the proposed period of extended operation. Thus, Citizens' contention lacks substantive merit and the Board should issue an initial decision dismissing it in its entirety.

Respectfully submitted,

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COUNSEL FOR
AMERGEN ENERGY COMPANY, LLC

Dated in Washington, D.C.
this 20th day of July 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	)	July 20, 2007
AmerGen Energy Company, LLC	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

AMERGEN'S PRE-FILED DIRECT TESTIMONY PART 1 INTRODUCTION, DRYWELL PHYSICAL STRUCTURE, HISTORY, AND COMMITMENTS

I. WITNESS BACKGROUND

Q. 1: Please state your names and current titles.

A. 1: (JFO) My name is John F. O'Rourke. I am a Senior Project Manager, License Renewal, for Exelon, AmerGen Energy Company, LLC's ("AmerGen") parent company. I have been in that position since 2006. I work in the Exelon corporate office located in Kennett Square, Pennsylvania.

(FWP) My name is Frederick W. Polaski. I am the Manager of License Renewal for Exelon. I have been in this position since 1996, first with PECO Energy Corporation, and since 2000 with Exelon. I also work in the Exelon corporate office located in Kennett Square, Pennsylvania.

(MPG) My name is Michael P. Gallagher, and I am the Vice President for License Renewal for Exelon. I have been in this position since January 2006. I also work in the Exelon corporate office located in Kennett Square, Pennsylvania.

Q. 2: Please describe your current responsibilities.

A. 2: (JFO) I am currently assigned as the Senior Project Manager for all aspects of the Salem/Hope Creek License Renewal Project. I am also assigned to the Oyster Creek Nuclear Generating Station ("OCNGS") License Renewal Project to assist with completion of license renewal activities. A copy of my résumé is attached as part of Applicant's Exhibit 1.

(FWP) I currently manage all aspects of the license renewal process for Exelon's and AmerGen's nuclear plants, including the OCNGS License Renewal Project. This includes oversight of the preparation of the License Renewal Application ("LRA") and Environmental Report, responding to requests for additional information from the Nuclear Regulatory Commission ("NRC"), participating in NRC audits and inspections associated with license renewal, and providing support for licensing proceedings before this Licensing Board. A copy of my résumé is also attached as part of Applicant's Exhibit 1.

(MPG) I am responsible for the overall implementation of license renewal for Exelon's nuclear plants, including the OCNGS License Renewal Project. A copy of my résumé is attached as part of Applicant's Exhibit 1.

Q. 3: Please provide a summary of your background and professional experience

A. 3: (JFO) I received a Bachelor of Science degree in Mechanical Engineering *cum laude* in 1973, a Master of Science degree in Mechanical Engineering in 1975, and a Master of Science degree in Engineering Management in 1983, all from Drexel University. I have been with Exelon (and its predecessors) for the past 34 years in various nuclear-related positions. From 2003 to 2006, I was the Assistant Site Engineering Director at OCNGS.

(FWP) I received a Bachelor's degree in Mechanical Engineering from the University of Delaware in 1971, with High Honors. I have been with Exelon (and its predecessors) for the past 36 years holding various nuclear-related positions, and have been involved in license renewal activities since 1996.

(MPG) I received a Bachelor's degree in Chemical Engineering from the Georgia Institute of Technology in 1981, and a Master's degree in Business Administration from St. Joseph's University in 1988. I have 26 years experience in the nuclear industry and have held a variety of key leadership positions within Exelon and its predecessors.

Q. 4: What is your experience related to the OCNGS drywell shell?

A. 4: (JFO) As the Assistant Site Engineering Director at OCNGS, I managed the resources within the Engineering Department to support the preparation of the LRA and to support the NRC audits and inspections following submittal of the LRA. Following my transfer to the License Renewal Project Staff, I assisted with the preparation of presentations to the Advisory Committee on Reactor Safeguards ("ACRS") and the ACRS License Renewal Subcommittee and was responsible for portions of presentations on January 18 and February 1, 2007.

(FWP) As manager of license renewal I have been involved in the development of the Aging Management Program for the drywell shell and related inspections and commitments associated with the OCNGS LRA submitted to the NRC on July 22, 2005, and the LRA supplement submitted to the NRC on December 3, 2006. I supported the NRC license renewal audits and inspections at OCNGS in 2005 and 2006. I also supported the response to the NRC Staff's requests for additional information related to the OCNGS LRA. I also was responsible for portions of AmerGen's OCNGS LRA presentations to the ACRS and the ACRS License Renewal Subcommittee on October 3, 2006, January 18, 2007 and February 1, 2007.

(MPG) As Vice President for License Renewal, I have overseen the OCNGS License Renewal Project since 2006, including the development of the LRA supplement submitted to the NRC on December 3, 2006 and AmerGen's OCNGS LRA presentations to the Advisory Committee on Reactor Safeguards ("ACRS") and the ACRS License Renewal Subcommittee on October 3, 2006, January 18, 2007 and February 1, 2007.

Q. 5: Would you please summarize the purpose of your testimony?

A. 5: (All) The purpose of our testimony is to introduce and summarize the seven parts of AmerGen's pre-filed direct testimony, as well as provide background information on: (1) the physical structure and functions of the drywell and the drywell shell, with particular focus on the sand bed region; and (2) the history of drywell corrosion at OCNGS, and subsequent corrective actions. We also will identify the current commitments related to AmerGen's Aging Management Program for the drywell shell in the sand bed region.

II. INTRODUCTION

Q. 6: Please summarize AmerGen's direct testimony and identify AmerGen's witnesses.

A. 6: (MPG) The contention that is the subject of AmerGen's testimony, as reflected in the Atomic Safety and Licensing Board's June 19, 2007 Memorandum and Order states that:

> AmerGen's scheduled UT [ultrasonic testing] monitoring frequency in the sand bed region [of the OCNGS drywell shell] is insufficient to maintain an adequate safety margin. More precisely . . . the issue presented is whether, in light of the uncertainty regarding the existence vel non of a corrosive environment in the sand bed region . . . AmerGen's UT monitoring plan is sufficient to ensure adequate margins.

AmerGen has organized its testimony in response to this contention into seven parts. In the first part, AmerGen provides background information on: (1) the key physical characteristics of the OCNGS drywell shell and sand bed region, including its size, shape, location in the OCNGS facility, materials of construction and operating environment; (2) the history of issues associated with corrosion of the external surface of the drywell shell in the sand bed region, including actions taken to prevent further corrosion; and (3) AmerGen's current docketed commitments to the NRC regarding preventing, monitoring, and controlling any future corrosion of the sand bed region of the drywell shell. AmerGen's testimony on these matters is being presented by Mr. John O'Rourke, Mr. Fred Polaski, and me.

Part 2 of AmerGen's testimony identifies the established acceptance criteria for determining whether the sand bed region of the drywell shell maintains sufficient thickness to meet applicable American Society of Mechanical Engineers ("ASME") Code and NRC regulatory requirements, and to perform its intended functions during the extended period of OCNGS operation under a renewed license. That testimony is being presented by Mr. Peter Tamburro and me.

Part 3 of AmerGen's testimony addresses how AmerGen estimates available margin by comparing ultrasonic testing ("UT") data from the sand bed region of the drywell shell to the above-described acceptance criteria. This part of the testimony also identifies the available margin of 0.064" and demonstrates why the margin is not smaller. This testimony is presented by Mr. Polaski, Mr. Tamburro, Mr. Julien Abramovici, and Dr. D. Gary Harlow.

Part 4 of AmerGen's testimony addresses why there is reasonable assurance that that leakage from the reactor cavity is the only known source of water on the exterior of the drywell shell in the sand bed region, and explains that AmerGen's commitments effectively eliminate the potential for water leakage from the refueling cavity onto the drywell shell exterior when the reactor cavity is filled with water. This part of the testimony also demonstrates that condensation on the exterior of the drywell shell in the sand bed region during normal operations is not credible, and that condensation during outages is entirely speculative. This testimony is presented by Mr. O'Rourke, Mr. Ahmed Ouaou, Mr. Howie Ray, Mr. Jon C. Hawkins, and Mr. Scott Erickson.

Part 5 of the testimony addresses the characteristics and excellent condition of the multi-layer epoxy coating system that has covered the exterior of the drywell shell in the sand bed region since the 1992 refueling outage. This part demonstrates that corrosion could not occur beneath the epoxy coating system and remain undetected during the period of extended operation. This testimony is presented by Mr. Jon R. Cavallo, Mr. Martin E. McAllister, Mr. Erickson, and Mr. Hawkins.

Part 6 of the testimony presents AmerGen's analysis of the potential for corrosion of the drywell shell in the sand bed region during the period of extended operation. That analysis takes into account, among other things, the OCNGS operating environment, the refueling schedule, drywell shell characteristics, and the potential for water to come into contact with the metal surface of the drywell shell in order to establish the amount of corrosion that theoretically could occur during the period of extended operation. That testimony is presented by Mr. Barry Gordon, Mr. Tamburro, Mr. Edwin Hosterman and me.

Finally, Part 7 of AmerGen's testimony presents AmerGen's conclusions on the adequacy of the planned UT frequency, as reflected in AmerGen's commitments to the NRC, to maintain an adequate safety margin for the drywell shell in the sand bed region during the period of extended operation. This testimony is presented by Mr. Tamburro and me.

III. PHYSICAL STRUCTURE OF THE DRYWELL

Q. 7: Please describe the general physical structure of the Oyster Creek drywell and drywell shell.

A. 7: (All) General information about the design, construction, and functions of the drywell and the drywell shell is in the LRA § 2.4.1 (Applicant's Exhibit 2), and the submittal prepared for the ACRS (Applicant's Exhibit 3).

In summary, the drywell shell is made of carbon steel plates that were welded together in the shape of an inverted light bulb, and is surrounded by a concrete shield wall. The drywell shell is approximately 70 ft. in diameter in its spherical section and 33 ft. in diameter in its cylindrical section. At the time of construction, the drywell shell was coated on the inside surface with inorganic zinc (Carboline carbozinc 11) and on the outside surface with "Red Lead" primer (TT-P-86C Type I). The shell is connected to the torus through ten cylindrical vent headers. Applicant's Exhibits 4 and 5 show the general containment structure design.

The drywell shell is embedded into a concrete pedestal atop the Reactor Building concrete foundation, as shown in Applicant's Exhibit 4. The bottom of the drywell shell sits at approximately elevation 2'3" (as shown in Applicant's Exhibit 5) and the top is at an elevation of approximately 100', relative to mean sea level.

Q. 8: What are the intended functions of the drywell shell?

A. 8: (All) The relevant functions of the drywell shell, as part of the OCNGS primary containment, are to accommodate the pressures and temperatures resulting from the break of any enclosed process pipe and to provide structural support to the reactor pressure vessel, the reactor coolant systems, and other systems, structures, and components housed within.

Q. 9: What is the "sand bed region"?

A. 9: (All) The drywell shell was designed with a sand bed on the exterior of the drywell shell between approximately elevations 8'11" and 12'3" to structurally support the shell as it transitions from being embedded in concrete on both sides below elevation 8'11", to being embedded only on the interior. The drywell shell is embedded in concrete on both sides from its bottom until approximately elevation 8'11", where the exterior drywell shell concrete floor is located. From elevation 8'11" upwards to approximately elevation 11'0" (beneath the torus vent headers) and elevation 12'3" (areas between the torus vent headers), the shell is embedded in concrete only on the interior, except at the location of two trenches excavated in the concrete floor in the 1980s for UT measurements. The sand was removed in the early 1990s, after which the exterior surface of the drywell shell in the sand bed region was cleaned and coated with a multi-layer epoxy coating system. Applicant's Exhibits 4 and 7 show the location of the "sand bed region."

Q. 10: Please describe the general physical layout of the sand bed region.

A. 10: (All) The sand bed region of the shell is spherical and is divided into ten "bays," each of which has an associated torus vent header. The ten bays are designated with the odd numbers one through nineteen. This is shown in Applicant's Exhibits 5, 6, and 7. Five drains, equally spaced throughout the bays and located within the concrete floor of the external sand bed region ("sand bed drains"), are designed to drain water that might reach the sand bed floor into the torus room below. Water from these drains is diverted through plastic tubing where it is collected in five-gallon plastic bottles.

Q. 11: What is the torus and what is its function?

A. 11: The torus is a torroidal-shaped steel pressure vessel encircling the base of the drywell. It is partially filled with demineralized water. One of the functions of the torus is to provide pressure suppression in the event of a loss-of-coolant accident.

Q. 12: Please describe the general design of the upper drywell.

A. 12: (All) Above the sand bed region, the drywell shell is within a few inches of the concrete shield wall, as can be seen in Applicant's Exhibits 4 and 7. The small gap between the shell and the shield wall was filled during construction with a compressible inelastic material known as "Firebar-D." This material is an asbestos fiber-magnesite cement product. After construction completion, this material was compressed by heating and pressurizing the drywell to provide an air gap to allow free expansion of the drywell under design basis loads and postulated events ("expansion gap"). Above approximately elevation 71'6", the upper drywell shell transitions from a spherical to a cylindrical shape. The reactor cavity is located above the upper drywell.

Q. 13: Please describe the reactor cavity.

A. 13: (All) The reactor cavity (or "refueling cavity") is located at the top of the Reactor Building concrete shield wall, as shown in Applicant's Exhibit 4. This cavity is only filled with water during refueling outages or other outages when the reactor vessel must be opened.

Q. 14: Please describe how any leakage from the reactor cavity is collected.

A. 14: (All) The reactor cavity drainage system is designed with a concrete trough that is located below the reactor cavity bellows seal to collect water that might leak while the cavity is filled with water. The location of the trough is identified in Applicant's Exhibit 4, and the trough detail appears as Applicant's Exhibit 8. This trough is equipped with a 2" drain line designed to direct leakage to the Reactor Building equipment drain tank and prevent it from entering the gap between the drywell shell and concrete shield wall. During those outages in which the reactor cavity is filled with water, leakage is minimized through the application of stainless steel tape and strippable coating to the reactor cavity liner.

Q. 15: Please describe the reactor cavity liner.

A. 15: (All) As shown in Applicant's Exhibit 9, the reactor cavity liner is fabricated from stainless steel plates, approximately 1/8" thick, welded together. The liner is inside the reactor cavity located approximately between elevations 91'9" and 119'3". It is approximately 37 feet in diameter and completely surrounds the drywell head.

Q. 16: Please describe the operating cycle for OCNGS.

A. 16: (All) OCNGS operates on a two-year refueling cycle. Refueling outages normally last between 19 and 30 days. The last refueling outage took place in October 2006 and the next outage is currently scheduled for October 2008.

Q. 17: Is the reactor cavity filled with water at any time other than refueling outages?

A. 17: (All) Yes. The reactor cavity may be required to be filled during a forced outage when the reactor vessel must be opened. Such outages are rare. For example, since at least 1990, OCNGS has not experienced a forced outage where the reactor cavity had to be filled with water.

Q. 18: Please describe the temperatures expected in the sand bed region during operations.

A. 18: (All) The reactor pressure vessel and other equipment located inside the drywell generate a significant amount of heat. These components heat the nitrogen-inerted environment inside the drywell during operations, which, in turn, heats the carbon steel drywell shell to temperatures significantly above the Reactor Building ambient temperature. Table 3.0-2 of the OCNGS LRA (Applicant's Exhibit 2) documents that the average normal operating temperature inside the drywell is 139° F. In other words, the drywell and drywell shell are the heat source and the ambient air at the exterior of the drywell is the heat sink.

Q. 19: Please describe the radiation levels expected in the sand bed region during operations.

A. 19: (All) Measured radiation levels inside the drywell at the sand bed elevation are in the range of 4.7 to 5.6 rads per hour, of primarily gamma radiation. While the expected radiation levels at the drywell exterior in the sand bed region would be slightly lower, these values can be used as conservative estimates of exterior sand bed region radiation levels.

IV. HISTORY OF CORROSION IN THE SAND BED REGION

Q. 20: Please describe the initial discovery of water on the exterior of the drywell in the sand bed region.

A. 20: (All) OCNGS began operation in 1969. In the 1980s, OCNGS discovered water coming from some of the sand bed drains. Extensive investigations were performed to identify the source of water and the leakage path. The source of the water was subsequently determined to be leakage through small cracks in the reactor cavity liner. This leakage occurred when the reactor cavity was filled with water, and should have been collected by the concrete trough located beneath the reactor cavity bellows. The amount of water, however, was greater than the capacity of the trough and drain pipe. Furthermore, the curb of the trough did not contain the water because of defects in the trough lip and a blocked drain, so the water instead overflowed into the expansion gap and down to the sand bed region. The trough lip defects and leakage path are shown in Applicant's Exhibits 7, 8 and 9. Later, the sand bed drains were discovered to be clogged, preventing proper drainage of water once it reached the sand bed region. Finally, portions of the sand bed floor were not properly finished to allow drainage towards the sand bed drains.

Q. 21: What caused the historical corrosion of the exterior of the drywell shell in the sand bed region?

A. 21: (All) The presence of water from the reactor cavity, sand (acting to keep the water in direct contact with an uncoated drywell shell), along with improper sand bed drainage caused corrosion of the exterior of the drywell shell prior to the implementation of corrective actions.

Q. 22: Please describe the location and extent of the historical corrosion.

A. 22: (All) The corrosion was not evenly distributed either among or within the ten bays. In general, corrosion was greatest in the vicinity of the torus vent headers and not in the middle of the bays. In addition, there was an air-water interface located near the top of the sand bed region, between approximately elevations 11' and 12', above which there was virtually no corrosion. For reference, the as-designed thickness of the drywell shell in the sand bed region is 1.154". The uneven distribution of corrosion resulted in a maximum general average metal loss of about 0.35" in part of Bay 19. Some bays exhibited almost no observable corrosion.

Q. 23: What actions did OCNGS take to correct the corrosion problem?

A. 23: (MPG, FWP) OCNGS took multiple mitigating actions in the 1980s and early 1990s to address the corrosion problem, including:

- clearing of the sand bed drains
- boring ten access holes through the concrete shield wall to access the ten bays to completely remove the sand
- manual cleaning of the exterior shell
- application of a multi-layer epoxy coating system on the drywell shell exterior in the sand bed region
- repair of the concrete floor located between the exterior surface of the drywell shell and the concrete shield wall in those bays that required repair
- application of epoxy caulk at the drywell shell/concrete floor junction in the former sand bed region
- repair of the leakage collection trough and clearing of the trough drain
- OCNGS also has applied stainless steel tape and a strippable coating to the reactor cavity during refueling outages to seal cracks in the reactor cavity liner and reduce leakage. Tape and strippable coating were not applied, however, during the refueling outages in 1994 and 1996.

Q. 24: Were these corrective actions effective?

A. 24: (All) Yes. As described in more detail in other parts of AmerGen's testimony, UT thickness measurements collected since 1992, coupled with visual inspections of the epoxy coating system performed during that time, demonstrate that corrosion of the exterior of the drywell shell in the sand bed region has been arrested.

V. REGULATORY COMMITMENTS RELATED TO CORROSION CONTROL IN THE SAND BED REGION

Q. 25: What is the purpose of AmerGen's regulatory commitments related to aging management of the drywell shell in the sand bed region?

A. 25: (MPG) AmerGen's regulatory commitments are part of AmerGen's ASME Section XI, Subsection IWE Primary Containment Inspection Program contained in Appendix A of the OCNGS LRA. This program is intended to provide reasonable assurance that the effects of aging will be adequately managed so that the intended functions of the drywell will be maintained consistent with the Current Licensing Basis ("CLB") for the period of extended operation.

Q. 26: What document describes these current commitments?

A. 26: (MPG) These commitments are contained in my letter to the NRC, dated February 15, 2007, titled "Additional Commitments Related to the Aging Management Program for the Oyster Creek Drywell Shell, Associated with AmerGen's License Renewal Application." (Applicant's Exhibit 10.)

Q. 27: Please summarize AmerGen's commitments related to aging management of the drywell shell in the sand bed region.

A. 27: (MPG) AmerGen's commitments to perform future actions related to drywell shell sand bed region corrosion control are summarized as follows:

(1) Perform the full scope of drywell sand bed inspections prior to the period of extended operation (*i.e.*, during the 2008 refueling outage) and every other (*i.e*, 2012, 2016, etc.) refueling outage thereafter. The full scope is defined as:

- UT thickness measurements from inside the drywell at the same locations where measurements were performed in 1996 (which are the same locations measurements were taken in 2006).
    - Statistically significant deviations from previous UT results will result in corrective actions that include the following: (1) perform additional UT measurements to confirm the readings; (2) notify the NRC within 48 hours of confirmation of the identified condition; (3) conduct visual inspection of the external surface in the sand bed region in areas where any unexpected corrosion may be detected; (4) perform engineering evaluation to assess the extent of condition and to determine if additional inspections are required to assure drywell integrity; and (5) perform operability determination and justification for operation until next inspection.
    - These actions will be completed prior to restart from the associated outage.
- Visual inspections of the drywell shell external epoxy coating system in all 10 bays. The Inservice Inspection Program (ISI) will be enhanced to require 100% of the epoxy coating every other refueling outage, in accordance with ASME Section XI, Subsection IWE.
- Inspection of the seal at the junction between the sand bed region concrete and the embedded drywell shell, per the Protective Coatings Program.
- UT thickness measurements at the external locally thinned areas inspected in 2006. This testing will be performed using the latest UT methodology with existing shell paint in place. The UT thickness measurements from 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 (ALARA). 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.

(2) AmerGen will verify that the reactor cavity concrete trough drain is clear from blockage once per refueling cycle. Any identified issues will be addressed via the OCNGS corrective action process.

(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 shell, including verification of the condition of the drywell shell coating and moisture barrier (seal) in the sand bed region. UTs will also be performed on any areas in the sand bed region where visual inspection indicates that 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 drains also will be monitored quarterly during the plant operating cycle. If leakage is identified, the source of water will be investigated and corrective actions taken or planned as appropriate. In addition, if leakage is detected, the following items will be performed during the next refueling outage:

    - Inspection of the drywell shell coating and exterior moisture barrier (seal) in the affected bays in the sand bed region;

    - UTs will be performed on any areas in the sand bed region where visual inspection indicates that the coating is damaged and corrosion has occurred; and

    - UT results will be evaluated per the current program

- Any degraded coating or moisture barrier will be repaired.

(4) 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.

Q. 28: Does this conclude your testimony?

A. 28: (All) Yes.

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

John F. O'Rourke — 7-17-07

John F. O'Rourke — Date

Frederick W. Polaski — Date

Michael P. Gallagher — Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

_______________________ _______________

John F. O'Rourke Date

Frederick W. Polaski 7/19/07

Frederick W. Polaski Date

_______________________ _______________

Michael P. Gallagher Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

_______________________________ _______________

John F. O'Rourke Date

_______________________________ _______________

Frederick W. Polaski Date

Michael P. Gallagher 7-17-07

_______________________________ _______________

Michael P. Gallagher Date

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	)	July 20, 2007
AmerGen Energy Company, LLC	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

AMERGEN'S PRE-FILED DIRECT TESTIMONY PART 2 ACCEPTANCE CRITERIA

I. WITNESS BACKGROUND

Q. 1: Please state your name and current title.

A. 1: (MPG) My name is Michael P. Gallagher, and I am Vice President of License Renewal for Exelon.

(PT) My name is Peter Tamburro, and I am a Senior Mechanical Engineer in the Engineering Department at the Oyster Creek Nuclear Generating Station ("OCNGS").

Q. 2: Please describe your responsibilities.

A. 2: (MPG) I previously described my witness background in Part 1 of this direct testimony. I rely on those answers here. A copy of my résumé is attached as part of Applicant's Exhibit 1.

(PT) A copy of my résumé is also attached as part of Applicant's Exhibit 1. In summary, my current responsibilities include implementing the OCNGS Drywell Vessel Monitoring Program. This program ensures that the Drywell Vessel (a.k.a. "shell") is inspected consistent with current regulatory commitments. It also defines the scope of future inspections and includes analyses of inspection results. I also am responsible for performing calculations related to the ultrasonic testing ("UT") thickness measurement data collected from the interior and exterior of the drywell.

My current responsibilities also include implementing the above- and below-ground piping monitoring program to ensure piping is capable of performing its intended function. This includes maintaining operating history, risk-ranking plant piping systems, establishing inspection scope and criteria, analyzing inspection results, sponsoring modification and replacement based on inspection results, and overseeing the design and installation of new piping systems.

Q. 3: Please provide a summary of your background and professional experience.

A. 3: (PT) I received my B.S. degree in Chemical Engineering from Clarkson University, Potsdam, New York, in 1980. I received my M.S. in Computer Science from Fairleigh Dickinson University, Teaneck, New Jersey, in 1986. I first registered as a Professional Engineer in the State of New Jersey around 1986. I have worked at OCNGS since 1990.

Q. 4: What is your experience related to the OCNGS drywell shell?

A. 4: (PT) I am very familiar with the OCNGS drywell shell. My involvement began in 1988, when I took over the responsibility for parts of the evaluation of the drywell shell corrosion issue. This entailed comparing the design requirements of the shell with inspection results. This also included setting the outage-related inspection scope, and reporting to the NRC throughout that time period on the results of those inspections.

More recently, since 1996, I have been responsible for ensuring upper drywell UT inspections are performed every other outage. I also have analyzed those inspection results for purposes of continued operations as well as for license renewal. I assisted in developing the inspection scope for the October 2006 refueling outage, and I analyzed the inspection results for the upper drywell as well as for the sand bed region. I prepared calculations that evaluated the internal and external UT thickness measurements collected from the sand bed region of the drywell during the 2006 refueling outage.

Q. 5: What is the nature of your involvement with drywell corrosion issues in the context of the OCNGS License Renewal Application?

A. 5: (PT) With respect to license renewal, I have provided historical perspective on drywell corrosion, corrective actions, and inspection. I reviewed and concurred with the drywell-related portions of the OCNGS License Renewal Application ("LRA") submitted to the NRC on July 22, 2005, various submittals to the NRC related to the LRA after its submittal, and the LRA supplement submitted to the NRC on December 3, 2006. I supported the NRC license renewal audits and inspections in 2006 as the lead engineer responsible for drywell–related inspections. I also supported the response to the NRC Staff's requests for additional information. I also participated, as a site engineer knowledgeable about drywell issues, in meetings with the Advisory Committee on Reactor Safeguards ("ACRS") on October 3, 2006, January 18, 2007 and February 1, 2007.

Q. 6: Would you please summarize the purpose of your testimony?

A. 6: (MPG, PT) There are two purposes of our testimony. First, we will identify the acceptance criteria that form part of the Current Licensing Basis that have been used since the early 1990s to ensure compliance with applicable American Society of Mechanical Engineers ("ASME") Codes and U.S. Nuclear Regulatory Commission ("NRC") requirements, and that will be carried forward into the license renewal period as part of AmerGen's Aging Management Program for the drywell shell. Second, we will explain that there are other values that have been used in various UT thickness calculations, all of which are more conservative than the acceptance criteria that are part of the Current Licensing Basis.

Q. 7: Please summarize your overall conclusions.

A. 7: (MPG, PT) Our overall conclusions are that the acceptance criteria are part of the Current Licensing Basis and have not changed over time. We have used more conservative values in various calculations to evaluate the UT measurement data. However, using more conservative values in those calculations is akin to operating a plant using an administrative limit, which is reasonable because it is more conservative than the licensing basis requirements (*i.e.*, the actual [redacted]

II. BACKGROUND ON THE ACCEPTANCE CRITERIA

Q. 8: Please provide some background on the acceptance criteria that AmerGen will use to demonstrate, through engineering analysis, compliance with the ASME Code requirements for the sand bed region of the OCNGS drywell shell during the period of extended operation.

A. 8: (MPG, PT) The design and function of the drywell is governed by 10 C.F.R. Part 50, Appendix A, General Design Criteria ("GDC") 2 ("Design Basis for Protection Against Natural Phenomena"), 4 ("Environmental and Dynamic Effects Design"), 16 ("Containment Design"), and 50 ("Containment Design Basis"). AmerGen complies with these GDC by meeting the applicable ASME Boiler and Pressure Vessel Code, standards, and specifications.

The drywell shell was designed with a sand bed on the exterior of the drywell shell between approximately elevations 8'11" and 12'3" to structurally retained to analyze the structural integrity of the drywell shell in this region if the sand were removed.

Q. 9: What failure modes is AmerGen's Aging Management Program for the drywell shell intended to address?

A. 9: (MPG, PT) The drywell shell in the sand bed region has two modes of potential failure which we will refer to as "buckling," caused by physical loads and stresses, and "pressure," caused by internal pressure.

These two modes occur under different postulated accidents. The limiting buckling scenario occurs during a postulated accident when the reactor is shutdown, the reactor cavity is filled with water, and the drywell is under a negative pressure of 2 psi. Under these postulated accident conditions, the weight of the water in the reactor cavity results in compressive stresses on the drywell shell.

The limiting pressure scenario occurs during a postulated loss-of-coolant accident ("LOCA") while the reactor is at full power. Under these postulated LOCA conditions, the atmosphere inside the drywell pressurizes to up to 44 psig, resulting in tensile stresses on the drywell shell.

Q. 10: What did GE find regarding the buckling failure mode if the sand in the sand bed region was removed?

A. 10: (MPG, PT) For buckling, GE's analyses determined that the relevant ASME Code requirements, which include a safety factor of two from ASME-Code allowable stresses for the refueling case (which is the limiting load combination), would continue to be met even if the shell in the sand bed region had a uniform thickness of 0.736". In other words, the *entire* shell in the sand bed region could have been manufactured and erected with a uniform thickness of 0.736" and it would have met ASME Code allowable stresses. Logically, and based on the acceptance criteria discussed below, a large area of metal must corrode in order for the drywell shell to no longer serve its physical support function. Therefore, buckling becomes an issue only when there is corrosion over a significant area of the shell.

Q. 11: Is there any significance to the fact that the applicable ASME Code includes a safety factor of two?

A. 11: (MPG, PT) Yes. The safety factor of two means that meeting the ASME Code results in actual stresses being half of the stress which would cause the drywell shell to physically buckle under the postulated refueling accident, which is the limiting load combination. As a result, the OCNGS drywell shell in the sand bed region could have a uniform thickness of 0.736" and still be more than 100% away from actually buckling.

Q. 12: What did GE find regarding the pressure failure mode?

A. 12: (MPG, PT) For pressure, GE's analyses determined that the relevant ASME Code requirements would continue to be met even if a very local area of the shell—2.5" in diameter—were as thin as 0.490". Therefore, only a small area of metal needs to be removed from a localized area of the shell to exceed its ability to retain internal pressures. For example, a very small hole in the shell would exceed the applicable ASME Code requirements for pressure because any hole in the shell will allow internal pressure to escape. That same small hole, however, would have no effect on buckling.

Q. 13: What about areas thinner than 0.736"?

A. 13: (MPG, PT) In the early 1990s, GE also performed sensitivity analyses on their original buckling analysis. These analyses sequentially evaluated locally-thinned areas using one square foot areas of 0.636" (0.100" less than 0.736") and 0.536" (0.200" less than 0.736"), each with a one-foot transition to the surrounding shell to a uniform thickness of 0.736". This configuration is shown in Applicant's Exhibit 11. In addition to using a uniform thickness for the rest of the drywell shell of 0.736", GE's analyses placed the locally-thinned areas in the location of the bay with the largest stresses, which is midway between the torus downcomer penetrations that divide each bay.

III. ACCEPTANCE CRITERIA THAT ARE PART OF THE OCNGS CURRENT LICENSING BASIS, AND THAT AMERGEN WILL CONTINUE TO USE DURING THE PERIOD OF EXTENDED OPERATION

Q. 14: What are the acceptance criteria for the sand bed region of the drywell shell that form part of the OCNGS Current Licensing Basis, and that AmerGen will continue to use during the period of extended operation to meet the ASME Code?

A. 14: (MPG, PT) There are three acceptance criteria: two for buckling and one for pressure.

The first buckling criterion is a general average thickness of 0.736". We will refer to this as the "general buckling criterion."

An area of average thickness less than 0.736" remains adequate if it meets the second buckling criterion which, as shown on Applicant's Exhibit 11, looks like a "tray." The center of the tray is 0.536" covering a 12" by 12" area, with a one-foot transition to the surrounding shell to a uniform thickness of 0.736". The transition area translates into a total contiguous area with thickness below 0.736" of nine square feet with a volume of 124.8 cubic inches. This criterion takes into account factors such as the location of the tray within the bay and configuration. We will refer to this criterion as the "local buckling criterion."

Finally, the pressure criterion is a local area average criterion with a thickness of 0.490" that is no more than 2.5" in diameter. We will refer to this criterion as the "pressure criterion."

Q. 15: Is there anything else you would like to add about these criteria?

A. 15: (MPG, PT) Yes. The two buckling criteria are volumetric criteria. This is best explained by using the local buckling criterion of 0.536". This criterion has the tray configuration described above. The total volume of this tray that is missing, with respect to a plate with a uniform thickness of 0.736", is 124.8 cubic inches. Therefore, it is important to understand that this criterion is not exceeded when localized corrosion removes a couple or even tens of cubic inches from the tray. The entire tray, on average, needs to corrode away for that loss of metal to be significant from a buckling perspective and to exceed the local buckling criterion.

Q. 16: Where can the Board locate the references to these acceptance criteria?

A. 16: (MPG, PT) The Current Licensing Basis is carried through for license renewal in the discussion of the acceptance criteria in the December 2006 License Renewal Application Supplement, page 13 of 74 (referencing the 0.736" general buckling criterion), and page 14 of 74 (referencing the 0.490" pressure and 0.536" local buckling criteria). These pages are attached as Applicant's Exhibit 12. The acceptance criteria also are each discussed in AmerGen's April 7, 2006 Response to the NRC Staff's Request for Additional Information on pages 3 of 35 through 7 of 35. These pages are attached in Applicant's Exhibit 13. A detailed explanation of the local buckling criterion also was provided to the NRC, also in April 2006, in response to NRC Audit Question #AMP-210, sub-question #3. This response is attached as Applicant's Exhibit 14. Finally, the NRC quotes AmerGen's April 2006 RAI response with respect to the acceptance criteria in its March 2007 SER at pages 4-55 to 4-58. These pages are attached in Applicant's Exhibit 15.

Q. 17: Have these acceptance criteria changed over time?

A. 17: (MPG, PT) No.

Q. 18: Then why are different values used in some of the calculations that evaluate UT measurement data?

A. 18: (MPG, PT) AmerGen and the former licensee of OCNGS have, at times, used different *calculation-specific* values in UT thickness evaluations. In each case, the calculation-specific value is more conservative than the acceptance criteria that are part of the Current Licensing Basis.

Q. 19: What do you mean by the term "calculation-specific values"?

A. 19: (MPG, PT) We will answer this question with various examples.

First, in the calculation used to evaluate the external UT measurement data collected during the 2006 refueling outage, AmerGen used the tray configuration from the local buckling criterion, but used 0.636" for the one square foot area in the center of the tray, instead of 0.536". This calculation, known as Revision 2 to the "24 Calc" was delivered to the Board on June 7, 2007, and is attached as

Applicant's Exhibit 16. In the prior revisions of the 24 Calc, namely Revs. 0 and 1, the calculation-specific value applied was 0.536" over a 12" by 12" area, without the tapering to 0.736" uniform thickness. These calculations are attached as Applicant's Exhibit 17 and 18. Although more conservative values were applied in these calculations, the local buckling criterion of 0.536" with tapering to 0.736" is discussed in each of the revisions as the "Local Wall" acceptance criterion on page 6 for Rev. 0, on page 10 for Rev. 1, and on page 12 for Rev. 2. Therefore, there should have been no confusion that this criterion has not changed over time.

Second, Technical Evaluation AR A2152754 E09 documented AmerGen's *preliminary* evaluation of the UT data collected in 2006 from the internal surface of the drywell shell in the sand bed region. We will refer to this evaluation, which is attached as Applicant's Exhibit 19, as "Tech Eval E09." In Tech Eval E09, AmerGen used the calculation-specific value of an area of 6" by 6" or smaller with a thickness of 0.693". On page 5, Tech Eval E09 explicitly states that this value is based on a Rev. 1 of the 24 Calc., which previously evaluated an area of this size and thickness in Bay 13. The 24 Calc., as discussed above, mentions the local buckling criterion but applies a more conservative value.

Finally, the calculation that documented AmerGen's detailed evaluation of the UT data collected in 2006 from the internal surface of the drywell shell in the sand bed region, known as the 41 Calc., used the same value as Tech Eval E09. Again, pages 10-11 of the 41 Calc. explicitly state that this value is based on Rev.

1 of the 24 Calc. which previously evaluated an area of this size and thickness in Bay 13.

There are also various internal and external correspondence referencing these different calculations and their calculation-specific values. The existence of these correspondence does not mean that the acceptance criteria that form part of the Current Licensing Basis have changed over time.

Q. 20: Is it reasonable to use calculation-specific values that are not part of the Current Licensing Basis to evaluate UT thickness measurements?

A. 20: (MPG, PT) Yes. All of these values are more conservative than the acceptance criteria that are part of the Current Licensing Basis. Using more conservative values in specific calculations is akin to operating a plant using an administrative limit, which is reasonable because it is more conservative than the licensing basis requirements (*i.e.*, the actual acceptance criteria used to satisfy code requirements). In each case, using a more conservative value assures compliance with the actual acceptance criteria.

Q. 21: Does this conclude your testimony?

A. 21: (MPG, PT) Yes.

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing it true and correct:

Michael P. Gallagher   7-17-07

Michael P. Gallagher   Date

Peter Tamburro   Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing it true and correct:

_______________________________ _______________

Michael P. Gallagher Date

Pat T [signature] 7/17/07

Peter Tamburro Date

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	)	July 20, 2007
AmerGen Energy Company, LLC	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

AMERGEN'S PRE-FILED DIRECT TESTIMONY PART 3 AVAILABLE MARGIN

I. WITNESS BACKGROUND

Q. 1: Please state your names and current titles.

A. 1: (FWP) My name is Frederick W. Polaski. I am the Manager of License Renewal for Exelon. My witness information is in Part 1 of this pre-filed testimony. I rely on those answers here.

(DGH) My name is Dr. David Gary Harlow. I am a Professor in the Mechanical Engineering and Mechanics Department at Lehigh University located in Bethlehem, Pennsylvania. I have been a full professor since 1992.

(JA) My name is Julien Abramovici. I am a consultant with Enercon Services, Inc. located in Mt. Arlington, New Jersey. I have been in this position since 2000. Enercon provides engineering services under contract with AmerGen.

(PT) My name is Peter Tamburro. My witness information is in Part 2 of this pre-filed direct testimony. I rely on those answers here.

Q. 2: Please describe your current responsibilities.

A. 2: (DGH) My current responsibilities include teaching and research.

I teach the following undergraduate courses related to probability and statistics: Statistics, Probability, Engineering Reliability, and Advanced Mechanical Design - Mechanical Reliability.

I also teach the following graduate courses related to probability and statistics: Applied Stochastic Processes, Mechanical Reliability, Random Vibrations, Probability Models in Mechanics, Stochastic Control, System Identification, and Nondeterministic Models in Engineering.

My research includes: probability and statistical modeling of failure processes in materials, aluminum alloys, steels, and composites; stochastic fracture mechanics; stochastic differential equations and their numerical solutions; mechanical and system reliability; applications of stochastic processes; and applied probability modeling. A copy of my résumé is attached in Applicant's Exhibit 1.

(JA) My current primary responsibilities at Enercon are to provide support to nuclear utilities, both foreign and domestic, on a number of technical issues including license renewal, inservice inspection ("ISI") relief requests, reactor vessel internals and reactor vessel weld inspections, control rod drive leakage evaluation and head penetration repairs, control rod drive mechanism venting investigations, ISI and inservice testing ("IST") program audits, Inconel 600 assessments, traveling screen problem investigations, steam generator evaluation and repairs, and Generic Safety Issue ("GSI") 191 resolutions. A copy of my résumé also is attached as part of Applicant's Exhibit 1.

Q. 3: Please provide a summary of your background and professional experience.

A. 3: (DGH) I have been teaching in the field of Mechanical Engineering and Mechanics since 1979. I received my Ph.D. in 1977 from Cornell University in the field of Applied Probability and Stochastic Processes. I received my Masters of Science degree from Cornell University in the field of Applied Mathematics one year earlier. I received a Bachelor of Arts degree from Western Kentucky University in the field of Mathematics and Physics in 1973.

I have applied my background in statistics to the issue of corrosion in various industrial applications. For example, for the past 15 years, I have studied corrosion and corrosion fatigue of aging aircraft. And I have developed stochastic models for pitting in metal.

(JA) I received my Bachelor of Science degree in Mechanical Engineering from the City College of New York in 1973. I received my Masters Degree in Systems Management from the University of Southern California two years later. I was employed by GPUN, the former owner of OCNGS, from 1978-2000. While at GPUN, I provided technical expertise on various component and system issues as well as American Society of Mechanical Engineers ("ASME") codes, with emphasis on ASME Section III, VIII and XI. I acted as responsible or independent reviewer for 10 C.F.R. § 50.59 evaluations and performed third-party design verifications on multi-discipline modifications. I am a Registered Professional Engineer in the State of New Jersey, and have been registered since 1980.

Q. 4: What is your experience related to the OCNGS drywell shell?

A. 4: (DGH) My involvement with the OCNGS has been as an expert consultant in the area of statistics. My first involvement with the OCNGS drywell shell was in 1990, assisting Mr. Tamburro and others at the plant in preparing statistically-sound ultrasonic testing ("UT") sampling plans for the upper and sand bed regions of the drywell shell. More recently, I have assisted AmerGen with analysis of statistics related to UT thickness measurement data of the drywell shell. Specifically, in late 2006, I was asked to review the analysis and calculation of UT thickness measurement data collected from the sand bed region of the drywell shell during the 1992 and 2006 refueling outages. I reviewed various calculations of these and other UT data prepared by AmerGen.

(JA) I am very familiar with the issue of corrosion of the sand bed region of the OCNGS drywell, having worked at the plant starting in 1978. I was involved with the discovery of corrosion in the 1980s, as well as in the development and implementation of subsequent corrective actions in my role as Manager, Components and Pressure Vessel. In this capacity, I managed the engineering activities of individuals responsible for: clearing the sand bed drains, performing statistical analysis of drywell shell data, removing drywell core samples, drywell trench excavation, leakage evaluations, and evaluating potential repair options. I left the company that formerly operated OCNGS in 2000.

I served as a consultant for the third party review of OCNGS License Renewal Application-related calculations. Specifically, I reviewed calculations to support license renewal from a mechanical perspective (for example, reactor vessel and internals, piping, and all of the fatigue analysis calculations). I also performed design verification for the second revision of Calculation C-1302-187-5320-024, which I will refer to as the "24 Calc." This calculation evaluated the UT thickness measurement data collected during the 2006 refueling outage from the exterior of the sand bed region. For design verification, I attested that the methodology, input, and output of that calculation are correct.

Q. 5: Please summarize the purpose of your testimony and overall conclusions.

A. 5: (All) The purpose of our testimony is to explain how AmerGen determined that the bounding remaining thickness of the OCNGS drywell shell in the sand bed region for the period of extended operation (*i.e.*, available margin) is 0.064" and not a smaller margin. This testimony also will address the uncertainties in evaluating the UT data.

The overall conclusions are that the acceptance criteria are easily satisfied for the period of extended operation. The general buckling criterion (that is 0.736") is easily satisfied because the smallest average of the UT grid measurements from the interior of the drywell shell is 0.800". The local buckling criterion is easily satisfied because there are no single UT measurements below 0.536", or any combination of UT measurements that suggest that this criterion has been exceeded. In fact, the thinnest single UT measurement obtained at any time between 1992 and the present is 0.602". Therefore, the pressure criterion is also easily satisfied because there are no single UT measurements below 0.490".

II. BACKGROUND ON HOW AVAILABLE MARGIN IS DETERMINED

Q. 6: Please provide some background on how AmerGen determines the available margin in the sand bed region of the drywell shell.

A. 6: (FWP, JA, PT) First, let's be clear that when we refer to the sand bed region, we are referring to that portion of the drywell shell that is between elevations 8'11" and 12'3" which was historically filled with sand on the exterior as generally shown on Applicant's Exhibit 4. Let's also be clear that we are referring to the thickness of the drywell shell in this region, regardless of whether it is measured from the interior or the exterior of the shell. With those clarifications, the available margin is based on UT thickness measurement data of the drywell shell taken from accessible locations on the inside and outside surfaces of the shell in the sand bed region.

Q. 7: When are these UT thickness measurement data of the sand bed region of the drywell shell collected?

A. 7: (FWP, JA, PT) These data are typically taken only during OCNGS refueling outages, which today occur approximately every two years. The last OCNGS refueling outage was in the Fall of 2006.

Q. 8: Why are these data only collected during refueling outages?

A. 8: (FWP, JA, PT) During normal plant operations, the interior of the drywell shell is inaccessible because the drywell is closed and inerted with nitrogen. The exterior of the drywell shell in the sand bed region is also inaccessible during normal plant operations because its entrances are physically blocked to provide radiation shielding. During refueling outages, the drywell is open, the exterior is accessible, and radiation dose rates are lower.

Interior UT data

Q. 9: For purposes of determining available margin, when were UT thickness measurements taken from the interior of the drywell shell in the sand bed region?

A. 9: (FWP, PT, JA) During the 1992, 1994, 1996, and 2006 refueling outages.

Q. 10: Are these UT thickness measurements taken as single UT points or from grids of UT points?

A. 10: (FWP, PT, JA) These measurements are taken from grids.

Q. 11: Why?

A. 11: (FWP, PT, JA) You take grid data to get an average thickness of an area which better represents your general drywell shell thickness. We are able to do this from the inside of the drywell because the surface is essentially flat, unlike the uneven surface which is characteristic of the corroded portions of the exterior surface of the drywell shell.

Q. 12: How many internal UT grids are there and what are their configurations?

A. 12: (FWP, PT, JA) There are a total of nineteen grids, each of which is centered on or near the 11'3" elevation of the drywell shell. The concrete curb prevents the grids from being placed at a lower elevation, except in two trenches that were excavated in the concrete in the 1980s. The size and spacing of the grids are established by a metal template which has been used each time UT measurements are taken. A picture of this metal template as presented to the ACRS is included as Applicant's Exhibit 21. Twelve of these grids are six inches square, each consisting of a total of forty-nine individual UT thickness measurement points. The remaining seven grids are rectangular—one inch by seven inches—using only the middle row of the same metal template. Seven UT points are collected from each of these seven rectangular grids. Also, there is at least one grid for each bay.

Q. 13: How do the UT technicians find these interior grids each time they take measurements?

A. 13: (FWP, PT, JA) There are permanent marks on the interior of the drywell shell that allow the metal template to be placed at the same location each time.

Q. 14: To what acceptance criteria are these interior UT grid data compared?

A. 14: (FWP, JA, PT) Two acceptance criteria apply to these grid data: the pressure criterion (where the thickness must be at least 0.490" over circular areas of diameters up to 2.5"), and the general buckling criterion of 0.736".

Q. 15: Why doesn't the local buckling criterion apply?

A. 15: (All) The UT data collected from the grids, whether they are the 49- or 7-point grids, can be averaged. The thinnest average grid from all of the bays is greater than 0.736", so the average is compared to the general buckling criterion. (*i.e.*, 0.736"). There is, therefore, no need to compare the average to the local buckling criterion (*i.e.*, 0.536").

Exterior UT data

Q. 16: During which refueling outages were UT thickness measurements taken from the exterior of the drywell shell in the sand bed region?

A. 16: (FWP, PT, JA) 1992 and 2006.

Q. 17: Are these UT thickness measurements taken as single UT points or from grids of UT points?

A. 17: (FWP, PT, JA) These measurements are taken as single points only.

Q. 18: Why?

A. 18: (FWP, PT, JA) Portions of the exterior surface of the drywell shell in the sand bed region that experienced historical corrosion have a very uneven surface. This uneven surface was caused by general corrosion that occurred before the exterior of the drywell shell in the sand bed region was cleaned and coated during the 1992 refueling outage with a multi-layer epoxy coating system. Two of the important requirements for a UT probe to provide an accurate measurement are that the surface area must be smooth over an area at least as large as the circular area of the UT probe, and that the UT probe needs to sit perpendicular to the surface of the metal it is measuring. Prior to coating with epoxy, the metal at over one hundred individual points was ground to allow the UT probe to sit perpendicular to the drywell shell surface. The circular areas were ground to no larger than two inches in diameter. These points are located throughout all ten drywell bays.

The single UT measurement points were selected because they were determined to be the thinnest locations in the sand bed region. To be able to perform UT measurements on a grid with 49 locations would require grinding much larger areas (6" by 6" or larger). Removing this metal would unnecessarily reduce the existing margin by reducing the thickness of the drywell shell.

Q. 19: How did the UT technicians find these exterior points in 2006?

A. 19: (FWP, PT) The single points were identified on UT data sheets as being located at certain vertical and horizontal distances from the intersections of known and easily visible welds. In 2006, AmerGen also marked the points for even easier identification in the future.

Q. 20: How many exterior UT thickness measurement points are there?

A. 20: (FWP, PT) During the 1992 refueling outage, OCNGS took over 120 UT measurements. However, some of these measurement points included two readings from the same location. In addition, OCNGS took some single point readings during that outage from the flat, essentially uncorroded exterior areas of the shell. These specific locations could not be relocated during the 2006 refueling outage. Accordingly, in 2006, single points were taken from 106 points of the previously measured locations.

Q. 21: To what acceptance criteria are these single, exterior UT thickness measurement points compared?

A. 21: (FWP, JA, PT) Two acceptance criteria apply to these single points. Individual points are compared to the pressure criterion (where the thickness must be at least 0.490" over circular areas of diameters up to 2.5"). Multiple points that are thinner than 0.736" and that are in close proximity to each other, are compared to the local buckling criterion (where the thickness must exceed 0.536" in the tray configuration described in Part 2 of this testimony and as shown in Applicant's Exhibit 11. These multiple points are also evaluated based on their spatial relationship to each other, on the spatial relationship within the tray, and on their location within the bay. For perspective, 23 of the 106 external readings in 2006 were less than 0.736."

Q. 22: What would happen if you computed the average of these single point data and compared it to the 0.736" general buckling criterion?

A. 22: (FWP, JA, PT) Any average would be overly conservative and result in an unrealistic assessment of the shell. Such an average would not allow you to determine available margin.

Q. 23: Why?

A. 23: (FWP, JA, PT) Because the single UT measurement points were selected because they were determined to be the thinnest locations in the sand bed region before that region was coated with epoxy. Thus the single-point UT measurements can tell you that you meet the applicable ASME Code, but not by how much.

III. METHOD USED TO ANALYZE AND INTERPRET THE UT DATA

Q. 24: What method do you use to analyze and interpret the UT data?

A. 24: (All) It depends on whether you are referring to the data from internal grids or external points. We will discuss the internal data first. As described on pages 4-60 of the March 2007 Safety Evaluation Report related to OCNGS License Renewal, for each internal grid of 49 UT measurements, the data are tested for statistical normality. If the data are normally distributed, then the average of the 49 points is calculated and used to represent the general drywell shell thickness in the tested area. If the 49 points are not normally distributed, then the grid is subdivided into datasets (usually 2, top and bottom) that are normally distributed. The average for each data set is then calculated.

(PT, FWP) For internal UT data collected through December 1988, the SER at pages 4-59 correctly documents the UT data evaluation as being memorialized in Calculation C-1302-187-5300-05 (the "05 Calc."). Portions of the 05 Calc. are attached as Applicant's Exhibit 22. For data collected through April 1990, the SER at 4-60 correctly documents the UT evaluation as being memorialized in Calculation C-1302-187-5300-011 (the "11 Calc."). The relevant portions of the 11 Calc. are attached as Applicant's Exhibit 23. The UT thickness measurement data collected through 2006 from the internal grids are evaluated using Calculation C-1302-187-E310-041 (the "41 Calc."). The 41 Calc. is attached as Applicant's Exhibit 20. The 41 Calc. is not mentioned in the SER because that calculation was completed in December 2006 and was not officially submitted to the NRC. The relevant portions of the SER are attached as Applicant's Exhibit 15.

The 05 Calc., 11 Calc., and the 41 Calc. each follow the established techniques for analyzing UT data for determining the best normal distribution and then acquiring the average of the data.

Q. 25: Did you omit any of the 2006 internal UT data from your computation of the normal distribution and, thus, the average?

A. 25: (PT) Yes. As an additional conservatism, I did not use UT measurements for purposes of computing the average if they were from points located over metal plugs, or were outside the normal distribution. As for the metal plugs, OCNGS took 2" diameter cores of the drywell shell from the inside of the drywell in the mid-1980s. These metal cores were replaced with new, metal plugs that, on average, are thicker than the surrounding corroded metal. When I separately calculated the average of these grids including the UT data from points over the metal plugs, I generated a higher average. To have included them would not have been conservative.

As for the other readings that were not over metal plugs, but were outside the normal distribution, I also have calculated the average with these points included and they too would have resulted in a thicker and, therefore, less conservative estimate. There is one exception: one point from one grid in Bay 1 (Grid 1D), that was outside the normal distribution. If I had included this point, the 2006 average would have been 1.088" as opposed to 1.122". However, this difference is not significant compared to the general buckling criterion of 0.736". So the omission of these points is irrelevant to the computation of the available margin.

Q. 26: Did you completely omit these data?

A. 26: (PT) No. Although I did not include them in computing the average thickness for the grid, I did consider them for comparison against the pressure criterion of 0.490".

Q. 27: What method did you use to analyze and interpret the external UT data?

A. 27: (All) The external UT data in each bay are not statistically treated. Rather, the raw UT data are compared against the relevant acceptance criteria without any statistical treatment.

(PT, FWP, JA) The external UT data evaluation is memorialized in Calculation C-1302-187-5320-024 (the "24 Calc."). Revision 0 of the 24 Calc. contains the evaluation of the UT data collected during the 1992 refueling outage, and is attached as Applicant's Exhibit 17. Revision 1 of the 24 Calc., which is attached as Applicant's Exhibit 18, provided better documentation for the UT data evaluation memorialized in Revision 0. Revision 2, which is attached as Applicant's Exhibit 16, contains the evaluation of the UT data collected during the 2006 refueling outage. The 24 Calc. is not discussed in the March 2007 SER because external UT data are not used to estimate available margin, and the NRC Staff's discussion in the SER is focused on available margin.

Q. 28: Can the 41 Calc. be used to identify the available margin using the Current Licensing Basis acceptance criteria for the drywell shell in the sand bed region?

A. 28: (PT, FWP, DGH) Yes.

Q. 29: Can the 24 Calc. be used to identify the available margin for buckling when compared against the Current Licensing Basis acceptance criteria for the drywell shell in the sand bed region?

A. 29: (PT, FWP, JA) No. Available margin for buckling is defined as the bounding remaining thickness of the OCNGS drywell shell in the sand bed region when compared to the Current Licensing Basis acceptance criteria. The 24 Calc. was developed to demonstrate compliance with the ASME Code. Demonstrating compliance can be done using conservative assumptions, without the refinement that would be required to identify the actual available margin. The 24 Calc. was developed using conservative assumptions that would not be appropriate for identifying the actual available margin when compared with the Current Licensing Basis acceptance criteria. In other words, it confirms that you meet the applicable ASME Code, but not by how much.

The 24 Calc. demonstrates that the thinnest locations are thicker than the pressure criterion (0.490") and the local buckling criterion (0.536"). There is not sufficient information from external UT measurements to compare against the general buckling criterion (0.736"). As stated above, to obtain enough information to determine margin based on exterior UT measurements would require grinding much larger areas (*i.e.*, 6" by 6" or larger) to be able to perform UT measurements on a grid with 49 locations. Removing this metal would unnecessarily reduce the existing margin by reducing the thickness of the drywell shell.

Q. 30: Please give me an example in the 24 Calc. of this conservatism that would make it inappropriate to identify the actual available margin?

A. 30: (PT, FWP, JA) One example is on Table 2-1 in Rev. 2 of the 24 Calc. Column three of that table documents the average of the external UT single-point thickness measurements in each bay. However, it is not realistic to average these data because they represent the thinnest points of the drywell shell in the sand bed region. Averaging them gives the impression that the metal between these points is as thin as these points, which is simply not the case. It is, however, conservative for purposes of demonstrating compliance with the general buckling criterion. The comparison was intended to show that if the average of thinnest points is greater than the general buckling criterion, then the actual average thickness over the same area would be much thicker and would also meet the criterion. When you average these points, as shown on Table 2-1 of the 24 Calc., you might incorrectly identify a bounding available margin of 0.047" in Bay 11. But the purpose of including that criterion on Table 2-1 was to simply illustrate compliance, not to estimate available margin. The summary section of the 24 Calc. (page 4) is clear about this conclusion: "This calculation demonstrates that the UT thickness measurements for all bays meet the required minimum uniform and local thicknesses."

IV. AVAILABLE MARGIN

Q. 31: What is the available margin in the sand bed region of the drywell shell for the purposes of license renewal when compared to the Current Licensing Basis acceptance criteria?

A. 31: (PT, FWP, JA) AmerGen has determined that the bounding margin of the drywell shell in the sand bed region is currently 0.064" and expects that to be the minimum margin when OCNGS enters the period of extended operation. This bounding margin is based on the general average thickness of 0.800" from the average of the data collected during the 1992 refueling outage from one of the 49-point grids in Bay 19, when compared against the general buckling criterion of 0.736". All other average UT data collected from other grids demonstrate an available margin greater than 0.064". So, *assuming uniform thickness over the* *entire shell*, AmerGen has 0.064" of thickness remaining before the general buckling criterion is exceeded. The minimum margin is greater in all the other bays. "Assuming uniform thickness over the entire shell" is an important and conservative assumption. If corrosion was localized on this 6" x 6" grid of 49 points, the available margin would be greater.

Q. 32: What about the single point UT thickness measurements from the exterior of the drywell shell in the sand bed region? Are any of them bounding with respect to available margin?

A. 32: (PT, FWP, JA) No. The external data are single points only. Individual UT data points are first compared to the pressure criterion of 0.490". The thinnest external single point is 0.602" from Bay 13. This results in an available margin of 0.112", which is more than 0.064". Therefore, the UT data from the Bay 19 interior grid remains the bounding available margin.

Q. 33: What about the local buckling criterion of 0.536" as shown in Applicant's Exhibit 11?

A. 33: (PT, FWP) The single UT data points, their location within each bay, and their spatial relationship to each other are compared to the local buckling criterion. AmerGen has performed these comparisons and determined that this is in no way the bounding scenario for buckling. As explained in Part 2 of this testimony, this criterion is a "tray" with a one-square-foot center that has an average thickness of 0.536" and sides that taper to 0.736". The total volume of this tray is 124.8 cubic inches. Therefore, this criterion is not exceeded when groupings of single points suggest the existence of localized corrosion that has removed a smaller portion than the total allowed cubic inches of reduction in metal volume. *The entire tray, on average, needs to corrode away for that loss of metal to be significant from a buckling perspective and to exceed the local buckling criterion.*

Q. 34: So what is the bounding volume in any of the bays, based on grouping of single external UT measurements?

A. 34: (PT, FWP) AmerGen estimated the bounding volume to be 124.5 cubic inches in Bay 19, meaning that an additional 124.5 cubic inches of metal would need to corrode away in order to exceed the local buckling criterion.

Q. 35: How did you arrive at that conclusion?

A. 35: (PT, FWP) The total volume of the tray that comprises the local buckling criterion is 124.8 cubic inches. Bay 19 contains the most single point UT measurements at or thinner than 0.736". In 2006, there were nine single point UT measurement locations on the exterior of the drywell shell in Bay 19. Four of these points were at or thinner than 0.736". To be conservative, we assumed that the circular area of 2.5-inch diameter area around each of these points is the same thickness as the points themselves. The combined volume of these four locally-thinned areas within Bay 19, each of which measured less than 0.736", is 0.251 cubic inches. When compared to the 124.8 cubic inch volume of the tray (local buckling criterion), it is clear that the effect on buckling is negligible, because approximately 124.5 cubic inches of margin remain. It is also, therefore, easy to see why these external UT thickness measurement points are not bounding for purposes of identifying the available margin in the sand bed region. A summary of the preceding discussion can be found on pages 90 through 93 of the 24 Calc., Rev. 2, although that calculation uses 0.636" so the volume discussed there is different.

Q. 36: How did you compare the groupings of individual UT points to the local buckling criterion in order to arrive at your conclusion?

A. 36: (PT, FWP, JA) The 24 Calc. explains how this comparison was performed. In summary, the coordinates of each external UT point were used as recorded on the UT data sheets. The 36" x 36" square (*i.e.*, nine square feet) that comprises the "tray" was then applied around the thinnest external points, in both x and y dimensions in order to develop an estimate of the total volume of metal remaining before that criterion would be exceeded.

The comparison also took into account the location within each bay of the groupings of UT points. The effective stresses for purposes of buckling are up to 20% less in the areas where the thinnest points are actually located than in the location where GE modeled them in their sensitivity analyses (discussed in the Background section of Part 2 of this testimony). This significant reduction in stress is because these points are located under or near the torus downcomer penetrations which structurally reinforce the drywell shell.

Q. 37: Is there reasonable assurance that the available margin is not going to change when AmerGen enters the period of extended operation?

A. 37: (All) Yes.

Q. 38: What is the basis for your opinion?

A. 38: (All) The evidence is the excellent condition of the multi-layer epoxy coating system, the comparison of the average UT thickness measurements taken from the interior grids starting with the 1992 refueling outage, and conservative assumptions about future corrosion which result in no change to the available margin. The epoxy coating system is discussed in Part 5 of this direct testimony, and future corrosion is discussed in Part 6. We will discuss the comparison of the UT data here.

As discussed above, UT measurement data from the internal grids were collected during the 1992, 1994, 1996, and 2006 refueling outages. These data were averaged, by grid, to produce the average thicknesses in the table below. The differences in these average thicknesses between the 1992 and 2006 refueling outages are consistent with the variability expected in UT data collected from the same locations over time. The limited variability of these data demonstrate that the thickness of the drywell shell has remained unchanged over the past 14 years. If corrosion had occurred that posed a buckling concern, it would be represented in these data – which represent data from 19 different locations throughout the sand bed region. And it is simply not there.

Average Thickness Measurements for the Sand Bed Region of the Drywell Shell

Grid Location by Bay	Split Grids	1992	1994	1996	2006
1D			1.101	1.151	1.122
3D			1.184	1.175	1.180
5D			1.168	1.173	1.185
7D			1.136	1.138	1.133
9A			1.157	1.155	1.154
9D		1.004	0.992	1.008	0.993
11A		0.825	0.820	0.830	0.822
11C	Bottom	0.859	0.850	0.883	0.855
	Top	0.970	0.982	1.042	0.958
13A		0.858	0.837	0.853	0.846
13D	Bottom	0.906	0.895	0.933	0.904
	Top	1.055	1.037	1.059	1.047
13C		1.149	1.140	1.154	1.142
15A			1.114	1.127	1.121
15D		1.058	1.053	1.066	1.053
17A	Bottom	0.941	0.934	0.997	0.935
	Top	1.125	1.129	1.144	1.122
17D		0.817	0.810	0.848	0.818
17/19	Top	0.976	0.963	0.967	0.964
	Bottom	0.989	0.975	0.991	0.972
19A		0.800	0.806	0.815	0.807
19B		0.840	0.824	0.837	0.848
19C		0.819	0.820	0.854	0.824

__UT Measurement Uncertainty__

Q. 39: Please explain the variability in these UT data.

A. 39: (FWP, PT) AmerGen addressed the variables surrounding UT measurements in its June 20, 2006, letter to the NRC that transmitted supplemental information related to the Aging Management Program for the drywell shell. Although the letter focused on why the 1996 internal UT grid data were, on average, thicker than previous measurements, the discussion is applicable to UT data in general.

Pertinent sections of that letter are reproduced on pages 4-53 of the March 7, 2007 SER, and are also reproduced below:

a. 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 the 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.

b. 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 [for the internal UT measurements] 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.

c. 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" 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.

* * * * *

h. 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.

Uncertainties Surrounding the Limited Number of UT Points
<u>on the Exterior of the Drywell Shell in the Sand Bed Region</u>

Q. 40: Are there uncertainties surrounding the limited number of UT points on the exterior of the drywell shell in the sand bed region?

A. 40: (FWP, PT) Yes.

Q. 41: What are those uncertainties and how were they created?

A. 41: (FWP, PT) Unlike the interior of the drywell shell, the exterior of the drywell shell in portions of the sand bed region has a very uneven surface that was caused by general corrosion that occurred before the exterior was coated with the epoxy coating system during the 1992 refueling outage. Prior to coating with epoxy, the metal at over one hundred individual points was ground to allow the UT probe to sit perpendicular to and flat against the drywell shell surface. Thus, unlike the interior of the drywell shell where AmerGen can take many UT measurements over large areas, only single UT measurements can be taken throughout the ten bays on the corroded exterior of the drywell shell in the sand bed region. The smaller data set from the exterior necessarily creates more uncertainty about the thickness of the shell between those points.

Q. 42: Do these uncertainties call into question the adequacy of AmerGen's Aging Management Program for the drywell shell in the sand bed region for the license renewal period?

A. 42: (All) No. The uncertainty is insignificant based on the following facts. First, the exterior UT locations were selected because they were determined by visual observations and micrometer readings to be the thinnest locations in the sand bed region. In addition, grinding most of these locations to prepare flat spots needed for UT measurements removed additional good metal. Thus, there is significant conservatism in UT measurements taken from these locations as compared to the metal thickness surrounding the ground areas.

Second, as discussed in Applicant's Exhibit 17 (page 3 of 54), for the two worst locations in Bay 13, 10-inch diameter molds of the irregular surface around the UT locations were taken in 1992 using epoxy putty. Micrometer readings were then taken of these molds to determine surface roughness. The micrometer readings from the 10-inch diameter area around these two UT locations demonstrate that there is significantly more margin than would be interpreted from the individual UT locations by themselves. We are confident, therefore, that the shell is thicker around these two locations.

The corrosion pattern on the exterior of the drywell shell in the sand bed region has been described as a "bath tub" ring, which typically corresponds to the interface between the air and former wetted sand. The internal UT grid locations correspond to this "bath tub" ring and, thus, are representative of the worst areas of corrosion.

Q. 43: Does this conclude your testimony?

A. 43: (All) Yes.

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing it true and correct:

Fred Polaski — 7/19/07

Fred Polaski | Date

Dr. David Gary Harlow | Date

Julien Abramovici | Date

Peter Tamburro | Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing it true and correct:

_______________________	____________
Fred Polaski	Date
David Gary Harlow	July 17, 2007
Dr. David Gary Harlow	Date
_______________________	____________
Julien Abramovici	Date
_______________________	____________
Peter Tamburro	Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing it true and correct:

Fred Polaski | Date

Dr. David Gary Harlow | Date

7-17-2007

Julien Abramovici | Date

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	July 20, 2007
AmerGen Energy Company, LLC	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	

AMERGEN'S PRE-FILED DIRECT TESTIMONY PART 4 SOURCES OF WATER

I. WITNESS BACKGROUND

Q. 1: Please state your names and current titles.

A. 1: (JFO) My name is John F. O'Rourke. I provided my witness information in Part 1 of this pre-filed testimony. I rely on those answers here.

(AO) My name is Ahmed Ouaou. I am a registered Professional Engineer specializing in civil/structural design and an independent contractor. I currently work at Exelon's office in Kennett Square, Pennsylvania.

(FHR) My name is Francis H. Ray. I am the Engineering Programs Manager at Oyster Creek Nuclear Generating Station ("OCNGS").

(JCH) My name is Jon C. Hawkins. I am a American Society of Mechanical Engineers ("ASME") Non-Destructive Examination ("NDE") Level III Inspector at Peach Bottom Atomic Power Station.

(SRE) My name is Scott R. Erickson. I am an ASME Non-destructive Examination ("NDE") Level III Inspector. I am employed by Sonic Systems International, under contract with General Electric Corporation ("GE"), providing engineering services at nuclear power plants.

Q. 2: Please describe your current responsibilities.

A. 2: (JFO) I previously described my current responsibilities in Part 1 of this direct testimony. I rely on those answers here. A copy of my résumé is attached as part of Applicant's Exhibit 1.

(FHR) I am responsible for overseeing the implementation of OCNGS license renewal commitments. Currently, I am also responsible for the supervision of the Engineering Programs Branch. The Engineering Programs ensure compliance with our regulatory and industry commitments. The scope of these Programs includes the ASME In-Service Inspection ("ISI") and Drywell Vessel Monitoring programs. I also supported NRC license renewal audits and inspections at OCNGS in 2005 and 2006, and was responsible for or assisted in preparing portions of the OCNGS license renewal presentations to the Advisory Committee on Reactor Safeguards ("ACRS") and the ACRS License Renewal Subcommittee on October 3, 2006, January 18, 2007 and February 1, 2007. A copy of my résumé also is attached as part of Applicant's Exhibit 1.

(AO) My current responsibilities include development of Aging Management Programs ("AMP") for license renewal applications, including the OCNGS License Renewal Application ("LRA"). A copy of my résumé also is attached as part of Applicant's Exhibit 1.

(JCH) My current responsibilities include daily NDE activities at the Peach Bottom plant, and NDE assistance during outages at other Exelon and AmerGen plants. I assisted with NDE activities at OCNGS during the 2006 refueling outage. A copy of my résumé is attached as part of Applicant's Exhibit 1.

(SRE) My responsibilities include NDE activities at various nuclear power plants on a contractual basis through GE. I assisted with NDE activities at OCNGS during the 2006 refueling outage. A copy of my résumé is attached as part of Applicant's Exhibit 1.

Q. 3: Please provide a summary of your background and professional experience.

A. 3: (JFO) I provided information about my background and experience in Part 1 of this direct testimony. I rely on those answers here.

(AO) I graduated from the University of Nevada at Reno with a Bachelor of Science degree in Civil Engineering and have taken graduate courses in civil engineering at the University of California, Long Beach. I am a registered Professional Engineer in California and Pennsylvania, and have over thirty years of civil/structural engineering experience, mostly in the nuclear industry. I helped develop the Oyster Creek LRA, including scoping, screening, and AMP development and review.

(FHR) I graduated from the University of Pittsburgh in 1980 with a Bachelor of Science in Civil Engineering. I have over 26 years of experience in the nuclear industry, including over 18 years in the civil and mechanical engineering disciplines with Stone and Webster Engineering Corporation, where I worked on design issues related to the construction and operation of ten different nuclear power plants. I have been a manager at OCNGS since January 2004.

(JCH) I am a Level III certified Inspector in Visual Testing ("VT") techniques, as well as other forms of NDE. I am also certified as an NDE Instructor. I have approximately nineteen years of NDE experience, including pre-service inspections at Limerick Nuclear Generating Station.

(SRE) I graduated in 1983 from the Hutchinson Vo-Tech Institute NDE Program. I have been certified as a Level II or Level III NDE Inspector for approximately 23 years. I have worked as an NDE Inspector at 25 nuclear power plants, including OCNGS, and at a variety of other industrial facilities, including fossil fuel power plants, chemical and oil refineries, and manufacturing and repair facilities. I have over 20 years experience as a Level II and Level III VT inspector.

Q. 4: Would you please summarize the purpose of your testimony?

A. 4: (All) The purpose of our testimony is to demonstrate that potential sources of water are limited to certain outages, because the only known source of water on the exterior of the drywell shell in the sand bed region is the reactor cavity liner which is filled with water only during refueling outages and during those other outages in which the reactor vessel must be opened. Observation of the exterior of the drywell shell in the sand bed region and the sand bed drains during the 2006 refueling outages confirms that the use of metal tape and strippable coating on the reactor cavity liner during outages can eliminate the presence of water from the exterior sand bed region. During that outage, there was no water observed in the exterior sand bed region or leakage observed from the sand bed drains.

II. Known Sources of Water in the Sand Bed Region

Q. 5: What was the historical source of the water that led to corrosion of the exterior surface of the drywell shell in the sand bed region at OCNGS?

A. 5: (AO, JFO) Historically, defects in the reactor cavity liner allowed water to leak behind the liner and run down into the reactor cavity concrete trough. If the flow rate from these defects exceeded the capacity of the two-inch trough drain line, or if the trough was damaged or blocked, then water would back up into the drywell expansion gap and flow by gravity to the outside of the drywell shell and into the exterior sand bed region, approximately 80 feet below.

Q. 6: At what point in the operating cycle did this leakage take place?

A. 6: (AO, JFO) The reactor cavity is only filled with water during refueling outages and during those other outages when the reactor vessel must be opened. Thus, leakage from the reactor cavity liner is only possible during these outages, and not during normal operations. The current refueling cycle is once every two years. As described in Part 1 of this testimony, forced outages where the reactor cavity had to be filled with water are rare, and OCNGS has not experienced such an outage since at least 1990.

Q. 7: What were the defects in the reactor cavity liner and when were they discovered?

A. 7: (AO, JFO) During the 1980s, non-destructive examinations revealed through-wall and surface defects near weld joints in the reactor cavity liner. The reactor cavity liner is shown in Applicant's Exhibit 9.

Q. 8: What was done to address the historical leakage problem?

A. 8: (AO, JFO) To address the defects in the reactor cavity liner, OCNGS chose to use metal tape and strippable coating as an effective, practical option to minimize leakage when the cavity is filled with water. OCNGS also repaired damage to the reactor cavity concrete trough, shown in Applicant's Exhibit 8, to minimize the possibility of water escaping the trough and entering the area between the concrete shield wall and exterior drywell shell.

Q. 9: Have these corrective actions been effective at OCNGS?

A. 9: (FHR, AO, JFO) Yes. The use of metal tape and strippable coating when the reactor cavity is filled with water has drastically reduced the amount of reactor cavity liner leakage. For example, during the 2006 refueling outage, observation of the reactor cavity liner leakage revealed a leak rate of approximately 1 gallon per minute. This level is well within the capacity of the reactor cavity trough drain system, which is estimated using standard hydraulic principles to be approximately 50 gallons per minute. The trough drain system directs this small amount of leakage into the controlled drainage collection system, so that it does not reach the exterior drywell shell. By comparison, for example, strippable coating was not used during the 1996 refueling outage, and water was seen leaking out of the sand bed drains during that outage.

Q. 10: Do we know if any water now reaches the exterior sand bed region during refueling outages?

A. 10: (FHR, AO, JFO) We do know that answer, and it is "No." Metal tape and strippable coating were used during the 2006 refueling outage. The trough drain was not blocked. No water was observed on the exterior of the drywell shell in the sand bed region, or in the sand bed drains during that outage. Daily inspections from the Torus Room during the 2006 outage identified no evidence of water leakage from the sand bed drains.

Q. 11: Did anyone who entered the sand bed region during the 2006 outage confirm that there was no water there?

A. 11: (JCH) Yes. I entered the sand bed region in Bay 5 (October 20) and Bay 7 (October 19), and did not see water either on the exterior of the drywell shell, or on the concrete floor of the sand bed region.

(SRE) Yes. I entered the sand bed region in Bay 1 (October 19), Bay 3 (October 20), Bay 9 (October 19), Bay 11 (October 20), Bay 13 (October 18), Bay 15 (October 20), and Bay 19 (October 20), and did not see water either on the exterior of the drywell shell, or on the concrete floor of the sand bed region.

Q. 12: In 2006, was there evidence that water had been in the sand bed region during prior refueling outages?

A. 12: (JCH, FHR) There was evidence that water had previously been present in the sand bed region, but this evidence is consistent with the failure to apply strippable coating during past refueling outages. For example, there were a number of white discolorations, up to approximately 3-4 feet in diameter on the concrete floor near some of the sand bed drains. These discolorations appear to be the residue left behind by water.

(FHR, JFO) Also, earlier in 2006, AmerGen identified water in three of the five plastic bottles in the Torus Room that collect water from the sand bed drains. Two of the bottles were found nearly full. We know the water in these bottles was old because the plastic drain lines from the sand bed drains were dry and there was no water on the Torus Room floor.

Q. 13: Are there any other potential sources of free-flowing water in the sand bed region?

A. 13: (FHR, AO, JFO) Extensive investigations of a large number of other plant components in the late 1980s and early 1990s provide reasonable assurance that these components are not sources of water in the sand bed region. These other plant components were: the bellows seal at the bottom of the reactor cavity (as shown in Applicant's Exhibit 8), the reactor cavity drain line, the refueling cavity metal trough and its associated gasket (also as shown in Applicant's Exhibit 8), the concrete trough located below the metal trough, the reactor cavity steps, the equipment pool and reactor cavity skimmer systems, the equipment pool liner, drain, and support pad, the spent fuel pool liner, and piping buried in concrete.

Q. 14: What about the ambient air? Can water contained in the ambient air condense on the coated exterior surface of the drywell shell in the sand bed region during normal operations?

A. 14: (FHR) No. Condensation will not occur unless the drywell shell is cooler than the surrounding air. As explained in Part 1 of this direct testimony, the temperature gradient across the drywell shell during normal operations runs from the hotter drywell interior to the cooler external sand bed region. This is because the reactor pressure vessel and other equipment located inside the drywell generate a significant amount of heat. The components heat the nitrogen-inerted environment inside the drywell during operations, which, in turn, heats the drywell shell to temperatures significantly above the Reactor Building ambient temperature. This temperature differential will prevent condensation from forming on the exterior of the drywell shell in the sand bed region.

Q. 15: But what about during outages? Can water condense on the drywell shell exterior in the sand bed region during refueling or other outages?

A. 15: (FHR) During the first few days of an outage, the temperature differential between the drywell shell and the ambient air in the Reactor Building will still exist, preventing condensation during this period. If the drywell chillers are used to cool the drywell interior, then it is theoretically possible for the drywell shell temperature to drop below the ambient Reactor Building air temperature. Chillers are used during refueling outages and other outages when extended access to the drywell is required. If condensation were to occur, however, then such postulated condensation would only last until restart, when the drywell shell temperature would rise and any water would evaporate. Thus, such postulated water would only remain for the duration of the outage.

Q. 16: Was there any evidence of condensation during the 2006 refueling outage?

A. 16: (FHR) No. There was no evidence of condensation on the exterior of the drywell shell in the sand bed region. Qualified NDE visual inspectors examined each individual bay during the 2006 refueling outage and their reports did not identify any condensation or other moisture.

(JCH) I believe that I was in at least six of the sand bed bays during the 2006 refueling outage. As part of my VT-1 inspections, I looked for but did not observe any condensation on the exterior of the drywell shell.

(SRE) I was in seven of the sand bed bays during the 2006 refueling outage. As part of my VT-1 inspections, I looked for but did not observe any condensation on the exterior of the drywell shell.

Q. 17: What conclusions, therefore, has AmerGen reached regarding the potential for water in the sand bed region?

A. 17: (FHR, AO, JFO) AmerGen has concluded, with reasonable assurance, that leakage from the reactor cavity is the only known source of water on the exterior of the drywell shell in the sand bed region. Moreover, AmerGen's commitments effectively eliminate the potential for water leakage from the refueling cavity onto the drywell shell exterior, during the only time when the reactor cavity is filled with water; *i.e.*, during refueling outages or other outages where the reactor cavity is filled with water. Condensation on the exterior of the drywell shell in the sand bed region during normal operations is not credible because the drywell and drywell shell are the heat source, and the Reactor Building ambient air is the heat sink. As for outages, the potential for condensation is entirely speculative.

Q. 18: Does this conclude your testimony?

A. 18: (All) Yes.

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

John F. O'Rourke 7-17-07

John F. O'Rourke Date

Ahmed Ouaou Date

Francis H. Ray Date

Jon C. Hawkins Date

Scott Erickson Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

John F. O'Rourke Date

Ahmed U Ouaou July 18, 2007

Ahmed Ouaou Date

Francis H. Ray Date

Jon C. Hawkins Date

Scott Erickson Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

John F. O'Rourke — Date

Ahmed Ouaou — Date

F. Harry Ray — 4/17/07

Francis H. Ray — Date

Jon C. Hawkins — Date

Scott Erickson — Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

John F. O'Rourke	Date
Ahmed Ouaou	Date
Francis H. Ray	Date
Jon C. Hawkins	7-18-07 Date
Scott Erickson	Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

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John F. O'Rourke Date

______________________________ ______________
Ahmed Ouaou Date

______________________________ ______________
Francis H. Ray Date

______________________________ ______________
Jon C. Hawkins Date

Scott R. Erickson 07/17/2007
______________________________ ______________
Scott Erickson Date

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	)	July 20, 2007
AmerGen Energy Company, LLC	)	
	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

AMERGEN'S PRE-FILED DIRECT TESTIMONY PART 5 THE EPOXY COATING

I. WITNESS BACKGROUND

Q. 1: Please state your names and current titles.

A. 1: (JRC) My name is Jon R. Cavallo. I am Vice President of Corrosion Control Consultants and Labs, Inc. I am also Vice-Chairman of Sponge-Jet, Inc., located in Portsmouth, New Hampshire, a company I helped found which designs and manufactures state-of-the-art surface preparation and decontamination systems.

(MEM) My name is Martin E. McAllister. I am an American Society of Mechanical Engineers ("ASME") Non-Destructive Examination ("NDE") Level III Inspector at Oyster Creek Nuclear Generating Station ("OCNGS").

(SRE) My name is Scott R. Erickson. My witness information is in Part 4 of AmerGen's direct testimony. I rely on those answers here.

(JCH) My name is Jon C. Hawkins. My witness information also is in Part 4 of AmerGen's direct testimony. I rely on those answers here.

Q. 2: Please describe your current responsibilities.

A. 2: (JRC) As Vice President of Corrosion Control Consultants and Labs, Inc., I provide corrosion mitigation professional engineering services in surface preparation, protective coatings and linings. I have held this position since 1998. Over the past year I have worked with AmerGen Energy Company, LLC ("AmerGen") on the OCNGS license renewal, including presenting portions of AmerGen's presentation before the Advisory Committee on Reactor Safeguards ("ACRS"). A copy of my résumé is attached as part of Applicant's Exhibit 1.

(MEM) My current responsibilities include daily NDE activities at OCNGS, and NDE assistance during outages at other Exelon and AmerGen plants. I supervised the VT-1 inspections of the sand bed area epoxy coating performed during the 2006 OCNGS refueling outage. A copy of my résumé is also attached as part of Applicant's Exhibit 1.

Q. 3: Please provide a summary of your background and professional experience.

A. 3: (JRC) I have worked on coatings and corrosion control at nuclear power facilities for over 35 years. Specifically:

From 1971 to 1983, I was employed by Stone & Webster Engineering Corporation in both the Boston and Denver offices. During this period, I specified coating systems for a number of new nuclear generating facilities as well as performed coating system failure analysis and attendant repair plans for operating nuclear generating facilities.

After leaving Stone & Webster, I worked with Metalweld, Inc., until 1986 as its Northeastern United States regional manager. I was the project manager for all of the protective coatings work for the Seabrook Nuclear Plant.

From 1986 to 1991, I was a Senior Associate in the consulting engineering firm of S.G. Pinney & Associates, Inc. During my employment with the firm, I performed protective coating and lining work at a number of nuclear generating facilities. I was the Professional Engineer assigned to all underwater protective lining work conducted by the firm.

From 1991 to 1998, I was an independent professional engineer performing corrosion engineering consulting services.

From 1998 to the present, I have worked in my current capacity as Vice President of Corrosion Control Consultants & Labs, Inc.

I received my B.S. degree in Engineering Technology, *cum laude*, from Northeastern University in Boston, Massachusetts, in 1979, completing my degree while working at Stone & Webster's Boston office. I have completed a variety of engineering and engineering management study programs, including U.S. Naval Nuclear Power Training, and programs at the University of Colorado (Engineering Project Management), and NACE International (Corrosion Prevention in Oil and Gas Production). I am a Registered Professional Engineer in four states, President of the Maine Society of Professional Engineers, and an SSPC-The Society for Protective Coatings certified Protective Coating Specialist.

I served as Editor of Electric Power Research Institute ("EPRI") Report 1003120 (formerly TR-109937), Revision 1, "Guideline on Nuclear Safety-Related Coatings." I also teach and assisted in developing the EPRI PSE (Plant Services Engineering) Protective Coatings Course. I am also the Principal Investigator of EPRI Report 1009750, "Analysis of Pressurized Water Reactor Unqualified Original Equipment Manufacturer Coatings," (Final Report, March 2005), and of EPRI Report 1014883, "Plant Support Engineering: Adhesion Testing of Nuclear Service Level I Coatings," (Final Report Expected to be Issued, July 2007).

I am active on a number of national technical societies including SSPC, NACE and ASTM. I have served as Chairman of the Northern New England Chapter of SSPC from 1991 to 1998, Chairman of the New England Chapter of SSPC from 2000 to the present, and was a member of the SSPC National Strategic Planning Committee. I was elected Chairman of ASTM Committee D-33 (Protective Coating and Lining Work for Power Generation Facilities) for the period 2004 through 2008. I have also served as Chairman of the Industry Coating Phenomena Identification and Ranking Table ("PIRT") Panel reviewing the work of Savannah River Technical Center on the USNRC Containment Coatings Research Project (Generic Safety Issue – 191).

(MEM) I graduated in 1978 from A.W. Beattie Technical School with a diploma in Nuclear/Metallurgy/Non Destructive Examination. I was an NDE Level II inspector/supervisor from 1978 to 1991 during the construction of the Susquehanna Steam Electric Station and Limerick Generating Station. Since

1991, I have been employed at OCNGS. I became an NDE Level III Inspector in 1997 for Visual Testing ("VT") and 1994 for Ultrasonic Testing ("UT") so I have over 9 years of experience as an NDE Level III Inspector in VT, and over 13 years of experience as an NDE Level III in UT. I am certified in, among other things, Level III VT, and as an NDE Instructor and was previously certified (1987-2005) as an American Welding Society/Certified Welding Inspector ("AWS/CWI") Visual Inspector.

Q. 4: Would you please summarize the purpose of your testimony?

A. 4: (All) The purpose of our testimony is to discuss the multi-layer epoxy coating system applied to the exterior of the sand bed region of the OCNGS drywell shell during the 1992 refueling outage. In particular, our testimony will discuss: (1) the nature and characteristics of the coating system, including its composition; (2) the suitability of this coating system for this particular application at OCNGS; (3) the methods used to apply the coating system; (4) the current condition of the coating based upon VT-1 visual inspections; (5) the anticipated life of the coating system; (6) the potential for corrosion to occur beneath the epoxy coating system through "pinholes" or "holidays"; and (7) the extent to which even very small amounts of corrosion would be detected by AmerGen's VT-1 inspections.

Q. 5: Please summarize your overall conclusions.

A. 5: (JRC) The epoxy coating system that has been applied to the OCNGS drywell exterior in the sand bed region is designed and appropriate for this application, is currently in excellent condition, and will be subject to appropriate periodic VT-1 inspections to ensure its continued integrity during the period of extended operation. I believe that this epoxy coating system should preclude further corrosion of the exterior shell in the sand bed region during the period of extended operation. I also believe the VT-1 inspections conducted at OCNGS would have disclosed even very small amounts of corrosion beneath the epoxy coating system if such corrosion was present.

(MEM, SRE, JCH) VT-1 visual inspections were conducted during the 2006 OCNGS refueling outage by trained and qualified inspectors. No evidence of coating deterioration was found and the coating system appears to be in excellent condition.

II. THE ROBUST EPOXY COATING SYSTEM

Q. 6: Please describe the nature and characteristics of the epoxy coating system on the OCNGS drywell.

A. 6: (JRC) The OCNGS drywell coating system was applied to the OCNGS drywell shell during the 1992 refueling outage. It is a 100% solids, three-layer epoxy coating system. It includes one pre-prime and two additional coats. The Devoe "Pre-Prime 167 Rust-Penetrating Sealer" is an epoxy coating that soaks and penetrates into the semi-irregular surface of the steel substrate and promotes coating system adhesion. It is recommended by the manufacturer for use in areas where, due to restrictions or economics, blasting or a thorough hand cleaning of the substrate may not be feasible. The two additional coats are comprised of a Devran-184 epoxy. In my affidavit supporting AmerGen's Motion for Summary Disposition, I stated that the pre-prime was red and the two outer coats were whitish-gray. In fact, the pre-prime is clear, and it is the middle and top coats that have contrasting pigments. This pigment contrast was chosen to ensure continuous and adequate coverage and for easy detection of signs of deterioration. The Devran epoxy coating system is designed for coating tank bottoms, including water tanks, fuel tanks, and selected chemical tanks.

Q. 7: Is this coating system suitable for protecting the OCNGS drywell shell from further corrosion during the period of extended operation?

A. 7: (JRC) Yes. This is an excellent coating system for this application. First, as described in the manufacturer's data sheet, it is designed for continuously submerged environments such as water tank bottoms. Multi-layer epoxy coating systems of this type are referred to as "barrier" systems and are the most effective moisture resistant coating systems used in submerged or wet environments. The environment around the OCNGS coating system is not a submerged environment. Thus, this epoxy coating system is quite robust for this application.

Second, one of the principal causes of deterioration of this type of coating system is ultraviolet ("UV") light. Since the drywell is located inside the Reactor Building, and the drywell shell is surrounded by the concrete shield wall, the coating is not exposed to UV light.

Third, another principal cause of deterioration of this type of coating system is mechanical damage, whether caused by abrasion or another mechanism. This coating system is isolated from moving parts and, during plant operation, is completely inaccessible.

Fourth, the coating system is designed to withstand the relatively benign temperatures present in the sand bed region. The coating system is rated for up to

250° F. Yet, as explained in Part 6 of AmerGen's direct testimony, the drywell shell in the sand bed region does not remotely approach this temperature under normal operating conditions. Thus, actual temperatures are well within the tolerances set forth by the manufacturer.

Fifth, this coating system is designed to withstand and should perform well under the radiation levels experienced around the exterior of the drywell shell. Devran, the manufacturer of the epoxy coatings, did not publish a radiation rating for this epoxy coating system. Based on my experience and research, I know that epoxy coating systems similar to the one applied to the sand bed region of the OCNGS drywell are resistant to total cumulative gamma radiation exposures up to approximately $1x10^9$ rads. From Part 1 of AmerGen's direct testimony, I know that the estimated dose to the epoxy coating system during OCNGS operations can be conservatively estimated at 5.6 rads per hour. At this dose rate, the coating system has received a dose of approximately 7.4×10^5 rads since it was installed during the 1992 refueling outage, and would expect to receive an additional dose of approximately 1.1×10^6 rads through the end of the period of extended operation, for a total of 1.8×10^6 rads. This dose is orders of magnitude lower than the doses we would expect to cause a failure of the epoxy coating system.

Finally, epoxies are the most commonly used type of coating in radiological environments in the nuclear industry. This type of coating has been used for years, quite successfully, in U.S. nuclear power plants. I participated as a consultant to EPRI in its 1996 survey of epoxy coatings then in use at nuclear power plants throughout the United States. From my review of these results, I know that these coatings have been used for decades with no signs of end-of-life deterioration. In fact, to the best of my knowledge, not a single epoxy coating in an atmospheric environment applied at a nuclear power plant has reached its end-of-life. Thus, for the purpose it is intended to serve on the OCNGS drywell shell, I consider this epoxy coating system to be a "workhorse" coating.

III. EXPECTED LIFE OF THE COATING

Q. 8: What is the expected life of this epoxy coating system?

A. 8: (JRC) The epoxy coating system should last for the life of the plant, including the extended period of operation, provided that proper inspections are conducted and, in the unlikely event that defects are identified, necessary corrective maintenance is performed. With appropriate inspections and proper maintenance, the coating system should last decades. The coating was nearly 14 years old when it was inspected during the October 2006 refueling outage, and it remains in excellent condition, as reported by those who performed the VT-1 visual inspections during that refueling outage.

Further, I know from my research and experience in the industry that many U.S. nuclear power plants are coated inside the primary containment (reactor containment, drywell, wetwell, etc.) with similar epoxy coating systems that are decades old. No "end of life" failures have been noted.

Q. 9: Please describe your basis for concluding that the OCNGS epoxy coating system should continue to perform its function for the period of extended operation.

A. 9: (JRC) First, as I described above, the epoxy coating system is in a relatively benign environment in terms of exposure to elevated temperature, mechanical damage, submersion in water, radiation, and UV light. Thus, none of the factors that would be most likely to contribute to deterioration of the coating over time are present.

Second, industry experience with epoxy coating systems of this type indicates that short life-span estimates, particularly in this environment, are overly conservative. In a number of U.S. nuclear facilities, epoxy coatings have been used for decades with no significant degradation. I know, from personal experience, two excellent examples: San Onofre Nuclear Generating Station, which entered service in the early 1980s, and McGuire Nuclear Generating Station, which entered service in the late 1970s. Both of these plants have epoxy coating systems similar to that used at OCNGS, on carbon steel surfaces that are located in environments similar to the OCNGS external surface of the drywell in the sand bed region.

Third, my experience with epoxy coating systems generally indicates that, typically in the early years after initial application, deterioration is found as a result of application errors, such as failure to properly cure the coating. However, after initial issues are resolved, there is an extended period, on the order of decades, where essentially no deterioration occurs. As an epoxy coating system approaches its end of life, I would expect signs of embrittlement and attendant cracking. I would also expect the embrittlement and attendant cracking to develop over a long period of time. In other words, the coating system would not be in excellent condition during one refueling outage, and be cracking and peeling in bulk off the drywell shell during the next refueling outage. The purpose of AmerGen's inspection program is to identify the early signs of deterioration, long before widespread coating failure could take place. In the U.S. nuclear industry there have been similar coating systems that have been in service for approximately 30 years that still do not exhibit such end of life deterioration.

III. THE EPOXY COATING SYSTEM IS IN EXCELLENT CONDITION

Q. 10: Are you familiar with the current condition of the epoxy coating?

A. 10: (JRC) While I have not inspected the actual coating myself, I have reviewed the inspection records from the VT-1 inspections performed during the 2006 OCNGS outage.

Q. 11: What conclusions can you draw from those inspection sheets and what is your basis for those conclusions?

A. 11: (JRC) VT-1 inspections performed by qualified inspection personnel are the ASME Code-approved means of assessing the condition of a coating system. As described by Messrs. McAllister, Erickson and Hawkins, the coating system on all 10 bays of the OCNGS drywell shell was inspected in 2006 by NDE Level II or III inspectors and no recordable indications were found. The results of those inspections give me very high confidence that the epoxy coating system is still in excellent condition.

Q. 12: Mr. Cavallo's conclusions regarding the current condition of the epoxy coating are based on the results of VT-1 visual examinations. For background, please describe what a VT-1 visual examination is.

A. 12: (MEM, JCH) AmerGen's protective coating monitoring program includes VT-1 visual inspections of the epoxy coating system by qualified inspectors in accordance with ASME Section XI, Subsection IWE. Under the VT-1 method, trained and qualified individuals inspect surfaces such as the drywell shell for evidence of flaking, blistering, peeling, discoloration, and other signs of degradation that would be early signs of potential coating failure. The VT-1 technique is used throughout the nuclear industry, on both boiling water reactors and pressurized water reactors. It is designed to be used on any type of steel or concrete surface, including irregular surfaces.

Q. 13: Citizens have suggested that there could be tiny holes in the epoxy coating, referred to as "pinholes" or "holidays," that could allow water to get behind the coating, causing corrosion of the underlying drywell shell. Can you explain this phenomenon?

A. 13: (JRC) Yes. A pinhole or holiday is a very localized defect in a coating created during the original application of coating as a result of problems in the application of the coating, such as failure to properly cure the coating. They are created by the chemistry of the coating (*e.g.*, solvent entrapment) or by the method of application. Pinholes are microscopic in size. Both pinholes and holidays are produced during application and cure of a coating. As such, pinholes and holidays are not defects that are caused by degradation of the coating over time.

Q. 14: What is your expert opinion regarding whether there are pinholes or holidays in the OCNGS epoxy coating system?

A. 14: (JRC) The epoxy coating system on the OCNGS exterior drywell steel is a three layer system. Since pinholes and holidays occur during the application process, the three-layer system chosen by OCNGS and the techniques and tools used in the application provide reasonable assurance that such pinholes or holidays would not extend through the three layers to expose the underlying metal substrate. If a pinhole or holiday exists in the primer coat, it would likely be covered up by the second coat. The likelihood that a pinhole or holiday would extend through both coats is quite small. The likelihood that a pinhole or holiday would extend through all three coats, in my view, is even smaller.

More importantly, pinholes or holidays would have existed since the coating was applied during the 1992 refueling outage. And water was reported to be present in the external sand bed region when strippable coating was not used on the reactor cavity liner during the 1994 and 1996 refueling outages. The corrosion that would have resulted from that water entering pinholes or holidays would be visible today due to the volume of corrosion products (iron oxides) and surface rust staining caused by the corrosion process.

Q. 15: Please describe the relationship between the volume of corroded metal and the volume of corrosion product (iron oxides).

A. 15: (JRC) As discussed by Mr. Barry Gordon in Part 6 of this direct testimony, as carbon steel corrodes, the reaction between the oxygenated water and the iron in the steel results in iron oxide products. Those products can occupy a volume of about 7-10 times greater than the volume of the underlying corroded steel. So, for example, Citizens have proposed a corrosion rate of 0.017" per year. If 0.017" of steel corrodes in a year at the site of a postulated pinhole or holiday, then between 0.119" and 0.170" of corrosion product would result. Four years of corrosion at that rate (the interval that AmerGen will perform visual inspections in the sand bed region) would result in between 0.476" and 0.680" of corrosion product. This amount of localized corrosion would, in a four-year period, generate an irregularly-shaped roughly hemispheric deformation called a "carbuncle" under the epoxy coating system of around ½ inch thickness and ½ inch in radius. The corrosion products would also seep out through the postulated pinhole or holiday onto the light gray epoxy coating surface.

Q. 16: Should such a defect be visible to an inspector performing a VT-1 inspection?

A. 16: (MEM) Yes. Any corrosion products that seep out onto the coated exterior of the drywell shell from a pinhole or holiday would be clearly visible during a VT-1 inspection.

Q. 17: Given the relationship between the volume of corroded steel and corrosion products which you described, what would be a reasonable, lower bound corrosion rate that would produce corrosion products that could reasonably be detected in a four year interval between AmerGen's planned VT-1 inspections?

A. 17: (JRC) VT-1 inspections should detect corrosion products caused by much lower rates of corrosion than 0.017" per year over a four year period. Even a corrosion rate of 0.002" per year at the site of a postulated pinhole or holiday would yield corrosion products that would cause a carbuncle of between 0.056" and 0.080" in the four year interval between inspections, and would emit visible corrosion products from the pinhole or holiday.

(MEM, JCH, SRE) Such a carbuncle, emitting a trail of corrosion products, would be visible in a VT-1 inspection performed by a qualified inspector.

Q. 18: Mr. Erickson, could you please describe your role in the 2006 OCNGS outage in reviewing the condition of the epoxy coating in the sand bed region of the drywell shell?

A. 18: (SRE) Yes. There were 10 separate VT-1 inspections conducted, one in each of the ten bays of the OCNGS drywell, to evaluate the condition of the epoxy coating system. I performed those inspections in 7 of the 10 bays (Bays 1, 3, 9, 11, 13, 15, and 19).

Q. 19: Mr. Hawkins, what was your role?

A. 19: (JCH) I was the field coordinator and also performed the VT-1 inspections in 2 of the 10 bays (Bays 5 and 7).

Q. 20: Mr. McAllister, what was your role?

A. 20: (MEM) I reviewed and signed off on the VT-1 inspection reports for 9 of the 10 bays (all bays except 19).

Q. 21: Were the personnel who performed the VT-1 inspections of the epoxy coating trained and qualified to perform those inspections?

A. 21: (MEM) Yes. I verified the training and qualifications of those personnel both prior to the inspections and again in preparation for this testimony.

Q. 22: How were the inspections performed?

A. 22: (MEM, SRE, JCH) The inspections were performed using approved specifications and procedures based upon ASME Section XI, Subsection IWE criteria. The personnel performing the inspections were qualified to perform those inspections in accordance with approved procedures. The specification called for direct visual inspection of the entire exterior surface from the base of the sand bed region concrete floor (approximately elevation 8'11") to the top where the drywell shell rises into the 3" gap with the concrete (approximately elevation 12'3"). This included the so-called "bathtub ring" of corrosion that occurred before the sand was removed and the epoxy coating system was applied, and included surfaces around the entire circumference of the drywell.

Q. 23: What were the results of these inspections?

A. 23: (All) The results of the inspections are reflected in 10 ASME IWE (Class MC) Containment Visual Examination Records. Applicant's Exhibit 24. The inspections indicated that the coating system is in excellent condition, and exhibited no recordable indications in any of the bays.

(SRE, JCH) We did not find any flaking, chipping, blistering, peeling, pinpoint rusting, cracking, chalking or discoloration, or any evidence of corrosion or corrosion products from the exterior drywell shell in the sand bed region. We also did not identify any gaps or failure to coat any portion of the sand bed region. There was a visible shine indicative of a coating in pristine condition.

Q. 24: Does this conclude your testimony?

A. 24: (All) Yes.

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

Jon R. Cavallo ______________________ July 17, 2007

Jon R. Cavallo — Date

______________________ ______________

Martin E. McAllister — Date

______________________ ______________

Scott Erickson — Date

______________________ ______________

Jon C. Hawkins — Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

_____________________________ _______________

Jon R. Cavallo Date

M McAllister 7-18-07

_____________________________ _______________

Martin E. McAllister Date

_____________________________ _______________

Scott Erickson Date

_____________________________ _______________

Jon C. Hawkins Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

______________________________	______________
Jon R. Cavallo	Date
______________________________	______________
Martin E. McAllister	Date
Scott R. Erickson	07/17/2007
Scott Erickson	Date
______________________________	______________
Jon C. Hawkins	Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

Jon R. Cavallo Date

Martin E. McAllister Date

Scott Erickson Date

7-18-07

Jon C. Hawkins Date

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	)	July 20, 2007
AmerGen Energy Company, LLC	)	
	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

AMERGEN'S PRE-FILED DIRECT TESTIMONY PART 6 FUTURE CORROSION

I. WITNESS BACKGROUND

Q. 1: Please state your name and current title.

A. 1: (BG) My name is Barry Gordon. I am an Associate with Structural Integrity Associates, Inc. ("SIA"), located in San José, California.

(MPG) My name is Michael P. Gallagher, and I am Vice President of License Renewal for Exelon.

(PT) My name is Peter Tamburro, and I am a Senior Mechanical Engineer in the Engineering Department at the Oyster Creek Nuclear Generating Station ("OCNGS").

(EWH) My name is Edwin Hosterman, and I am a Senior Staff Engineer in the Corporate Engineering Programs Group in Exelon's Headquarters in Kennett Square, Pennsylvania.

Q. 2: Please describe your current responsibilities, beginning with a summary of your background of professional experience.

A. 2: (MPG) I provided my witness information in Part 1 of this pre-filed testimony. I rely on those answers here.

(PT) I provided my witness information in Part 2 of this pre-filed testimony. I rely on those answers here.

(BG) For the past 38 years, I have been an engineer focusing on corrosion and material issues in light-water reactors. I received my B.S. and M.S. degrees in Metallurgy and Material Science from Carnegie Mellon University in 1969 and 1971, respectively. Since then, I have completed additional courses from M.I.T., the University of Pittsburgh, and the National Association of Corrosion Engineers ("NACE") in Corrosion Science.

I am a Registered Professional Engineer in Corrosion Engineering in the State of California (#208), a Registered Corrosion Specialist with NACE International (#1986), and a Member of the International Cooperative Group on Environmentally Assisted Cracking ("ICG-EAC").

I have been certified as an Instructor for the International Atomic Energy Agency ("IAEA") since February 2001, and am an Adjunct Professor at the Colorado School of Mines, in Golden, Colorado. I teach "Corrosion and Corrosion Control in LWRs" to utility engineers and the U.S. Nuclear Regulatory Commission on behalf of Structural

Integrity Associates, Inc., and have taught "Corrosion and Corrosion Control in BWRs" for utility employees on behalf of GE Nuclear Energy ("GE"). I have held instructor credentials for Engineering in California Community Colleges since 1986.

From 1969 to 1975, I was employed as a materials engineer by Westinghouse Electric at the Bettis Atomic Power Laboratory, located in West Mifflin, Pennsylvania. From 1975 to 1998, I was employed by GE, located in San José, California. While at GE, I was a technical expert in corrosion engineering, a project manager in corrosion technology, and a program manager in stress corrosion cracking.

I have been with SIA since 1998. My current responsibilities include addressing materials and corrosion issues in the nuclear industry in a wide range of contexts including reactor internals, piping, fuel hardware, water chemistry transient and core flow issues, weld overlays and repairs, crack growth rate modeling, alloy selection, failure analysis, license renewal, NRC inspection relief, dry fuel storage, and decontamination.

A copy of my résumé is attached as part of Applicant's Exhibit 1.

(EWH) For the past 30 years, I have been an engineer in the nuclear industry. For the last 20 years, my primary focus has been in the areas of fluid flow and heat transfer analysis, and issues related to power plant heat exchanger and service water system performance. I am currently the Exelon Nuclear Subject Matter Expert for Heat Exchangers and Heat Exchanger testing and inspection. I have been a Registered Professional Engineer in the State of Pennsylvania since 1983.

I received my B.S. degree in Nuclear Engineering from the Pennsylvania State University in 1977. From 1977 to 1979, I was employed as an engineer-trainee by Burns and Roe, in the nuclear analysis group in Paramus, N.J. and the WNP-2 site in Richland

Washington. From 1979 to 1983, I was employed by Bechtel Corp. as a field engineer at the Limerick Nuclear Generating Plant in Limerick, Pennsylvania. From 1983 to 1988, I was employed as a systems engineer, by Pennsylvania Power & Light Company, in the Allentown, Pennsylvania headquarters.

From 1988 to 1992, I was employed by Bechtel Corp. as a senior engineer and Mechanical Group Supervisor in the Pottstown, Pennsylvania office. From 1992 to 1998, I was employed by PECO Energy as a Senior Engineer in their nuclear headquarters, specializing in post-accident HVAC analysis, fluid flow and heat transfer analysis, and service water and heat exchanger issues. From 1998 to 2000, I was employed by Apollo Consulting, Inc., Senentec, Inc., and Hosterman Engineering Inc. as a private consultant specializing in post-accident HVAC analysis as well as fluid flow and heat transfer analysis related to power plant systems and heat exchanger performance. I have been employed by Exelon since 2000.

A copy of my résumé is also attached as part of Applicant's Exhibit 1.

Q. 3: What is your experience related to the OCNGS drywell shell?

A. 3: (BG) I am familiar with the historical corrosion of the OCNGS drywell shell because I started working on that issue in the mid-1980s as the OCNGS drywell project manager for GE. I had the opportunity to review, among other things, 2"-diameter core samples taken of the OCNGS drywell shell. These core samples and other data demonstrated that metal thinning was caused by general corrosion that was more severe in some bays than in others. More recently, I prepared an evaluation report on the possible corrosion of steel embedded in concrete on the exterior of the drywell (June 5, 2006) and on effects of water on corrosion propensities of concrete embedded steel identified in the interior of the drywell (November 3, 2006). I also testified before the Advisory Committee on Reactor Safeguards ("ACRS") License Renewal Subcommittee on January 18, 2007, on these subjects.

Q. 4: Would you please summarize the purpose of your testimony?

A. 4: (All) The purpose of our testimony is to present expert opinion on what corrosion of the drywell shell could theoretically occur in the sand bed region of OCNGS during an extended twenty-year period of renewed plant operation.

Q. 5: Please summarize your overall conclusions.

A. 5: (All) There is no expected significant corrosion of the exterior surface of the drywell shell based on the conditions anticipated during the license renewal term at OCNGS. Corrosion requires the ongoing presence of an exposed anode, *i.e.*, the metal surface, and a cathodic reactant such as dissolved oxygen in an electrolyte (*e.g.*, water). The exterior epoxy coating system is designed to preclude corrosion since it separates the metal surface from the electrolyte containing the dissolved oxygen cathodic reactant. In other words, corrosion of the external surface of the drywell shell has been arrested, and AmerGen's Aging Management Plan is intended to maintain these conditions throughout the period of extended operations.

If there are undetected defects in the epoxy coating system covering the exterior drywell shell, and those undetected defects allow oxygenated water to come into contact with the underlying metal shell, then we would expect corrosion to be limited to 0.0014" every two years (*i.e.*, the time between the beginning of one refueling outage and the start of the next refueling outage). This is based on Citizens' proffered corrosion rate of

0.017", coupled with the fact that oxygenated water could only come into contact with the exterior drywell shell during the short duration of a refueling outage.

II. EXTERNAL DRYWELL SHELL SURFACE

Q. 6: What historical information is relevant to your testimony regarding possible corrosion of the external OCNGS drywell shell surface during an extended term of plant operation?

A. 6: (BG) Prior to the corrective actions leading up to the application of the epoxy coating system during the 1992 refueling outage, the exterior of the OCNGS drywell shell in the sand bed region experienced corrosion. Corrosion requires the simultaneous existence of four fundamental parameters, *i.e.*, two electrodes (anode and cathode) and two circuits (electrical and ionic). If any one of the four corrosion fundamental parameters is eliminated, corrosion cannot occur. Since the anode, cathode and electrical circuit typically exist simultaneously on the metal surface, corrosion can be eliminated by the removal of the ionic circuit/electrolyte, *i.e.*, water or the cathodic reactant dissolved oxygen in the water.

(BG, MPG, PT) The corrosion in the sand bed was caused by the presence of oxygenated water which leaked from the reactor cavity during refueling outages, and whose drainage from the sand bed region was limited due to obstructed sand bed drains and unfinished concrete floors in some bays, which did not convey the water to the drains. In addition, the sand itself, once wet, kept the water in contact with the then-uncoated exterior drywell shell beyond the duration of the refueling outage.

The actions that OCNGS implemented corrected these problems. Specifically, the water-retaining sand in the sand bed region was removed from all ten drywell bays, which prevented any water present in the sand bed region from being held against the drywell shell. The drywell shell exterior in the sand bed region was cleaned and coated with a multi-layer, epoxy coating system. This system is designed to prevent two of the four required fundamental parameters for corrosion, *i.e.*, the electrolyte and the dissolved oxygen cathodic reactant from coming into contact with the underlying metal shell. This explains why there needs to be some kind of degradation of the epoxy coating system before additional corrosion can occur at OCNGS.

Q. 7: You mentioned that water is required to cause corrosion. Would moisture in the air be sufficient?

A. 7: (BG) No, moist air by itself is not sufficient to cause corrosion. Based on fundamental corrosion principles, moisture in the air would need to condense on the underlying metal shell to cause additional corrosion.

(BG, MPG, PT) Water condensing on an intact epoxy coating system would have no effect on the underlying metal.

Q. 8: What would corrosion have looked like when it occurred on the uncoated exterior metal surface of the drywell shell in the sand bed region at OCNGS?

A. 8: (BG) When corrosion occurs, iron ions enter the electrolyte and combine with the hydroxide formed during the oxygen reduction reaction, to form various, sometimes complex, iron oxides. Combined, these oxides can take on a range of colors, from orange to black. For the exterior of the drywell shell, these iron oxides occupied a volume much larger than the metal consumed in the corrosion reaction. These iron oxides can occupy a volume that is between approximately seven and ten times greater than the metal being corroded. So the surface of the corroded metal becomes not only discolored but also very uneven.

Q. 9: Would corrosion look different if it were caused by water from the reactor cavity, as opposed to water condensing on the drywell shell from ambient air?

A. 9: (BG) It would probably look the same, but the corrosion rate might be faster for water from the reactor cavity versus condensed water.

Q. 10: Why the potential difference?

A. 10: (BG) Corrosion can be accelerated by the presence of impurities in the water, such as salts, since ions present in the water increase conductivity of the electrolyte. I know from my work at OCNGS, when I was with GE, that the water from the refueling cavity contains low levels of impurities, but that the historical corrosion was accelerated by impurities picked up during the water's transport to the external sand bed region and present in the air and the sand. Condensed water, however, is pure water and would have a lower conductivity than the reactor cavity water. That is, it would typically not contain corrosion–accelerating impurities. Thus, the corrosion rate from condensed water will be slower than for water from the reactor cavity. Although condensed pure water on the surface could eventually pick up some impurities from the atmosphere, thus increasing the conductivity of the solution, the average corrosion rate would still be less with condensed pure water.

Q. 11: So what is your expert opinion about corrosion of the external surface of the OCNGS drywell shell in the sand bed region during the period of extended operation?

A. 11: (BG, MPG, PT) There can be no future corrosion unless the epoxy coating system fails in some manner. As mentioned previously, corrosion in this system requires the ongoing presence of oxygenated water and an exposed metal surface. The epoxy coating will prevent water with its dissolved cathodic reactant oxygen from coming into contact with the underlying metal shell.

Q. 12: What would your answer be if you assumed that the coating system deteriorates during the period of extended operation, such that water and oxygen could come into contact with the underlying carbon steel drywell shell in the sand bed region?

A. 12: (BG) If I assume that the coating system deteriorates, then I have present three of the four fundamental parameters needed for corrosion; namely, the anode, cathode and electrical circuit on the surface of the exposed metal. But I still need the ongoing presence of water (ionic circuit/electrolyte) containing dissolved oxygen to have corrosion of the underlying carbon steel drywell shell.

Q. 13: Please rely on the assumptions about the presence of water in the sand bed region provided in Part 4 of this direct testimony to provide an expert opinion about corrosion of the external surface of the drywell shell in the sand bed region during the period of extended operation.

A. 13: (BG) Using Part 4 of this direct testimony, I would limit the presence of water in the sand bed region to a short period of time during refueling outages (*i.e.*, approximately 30 days every 24 months). As discussed in Part 1, forced outages where the reactor cavity has to be filled with water are rare. Therefore, I am not including these rare events in any of my assumptions. This is because I am already introducing significant conservatism into my analysis by using the upper end refueling outage duration of 30 days, rather than 19 days. Part 4 also explains that, while it is theoretically possible for the drywell shell temperature to drop below the ambient Reactor Building air temperature, and thus allow condensation on the exterior surface of the drywell shell in the sand bed region, this could only occur during those outages in which the drywell chillers are used. Once the plant exits the outage, any water on the exterior of the drywell shell would evaporate.

Q. 14: So what is your expert opinion about the amount of corrosion of the external surface of the drywell shell in the sand bed region, if you assume the epoxy coating system deteriorates and you assume the presence of water once every two years for approximately 30 days?

A. 14: (BG) Using those assumptions, it is my expert opinion that AmerGen could expect to lose up to a total of 0.0014" during each refueling outage.

Q. 15: What is the basis for your opinion?

A. 15: (BG) In addition to the assumptions about coating failure and presence of dissolved oxygen in the water, I used the historical corrosion rate cited by Citizens of 0.017" per year. This, of course, is extremely conservative because, among other things, corrosion rates that occurred prior to removal of the sand from the sand bed region simply are not representative of the potential corrosion rates after removal of the sand, and potentially during the extended period of plant operation.

To calculate the total corrosion over a refueling outage, I divided 0.017" by 365 days to get a daily corrosion rate of 0.0000465". I then multiplied this corrosion rate by 30 days to compute the total corrosion expected during a month-long refueling outage, which is 0.001397". I rounded that number to 0.0014".

Q. 16: Is your analysis conservative in any other way?

A. 16: (BG) Yes. I also assumed that the water is not detected. You know from Part 1 of this direct testimony that AmerGen's Aging Management Program for the drywell shell includes monitoring the refueling cavity liner drain during outages, as well as the five sand bed region drains both quarterly during operations and daily during outages.

Second, I know from Part 4 of this direct testimony, that if the source was theoretical condensation, that such condensation would not occur until later in the refueling outage. Of course, no water of any kind was observed during the 2006 outage.

Third, I assumed that the dissolved oxygen's contact with the metal surface is not mitigated by the presence of corrosion products. This is conservative because general corrosion rates decrease with time when corrosion films, even non-passive corrosion films, are produced on the metal surface since they create a diffusion barrier for metal cations and/or dissolved oxygen transport that reduces the amount of subsequent corrosion of the shell.

Q. 17: Why, in your expert opinion, did you not include corrosion beyond the refueling outage?

A. 17: (BG) I did not include additional days of corrosion because, as mentioned previously, corrosion requires, among other things, an electrolyte, *i.e.*, ongoing source of water. Once the refueling outage ends, there is no additional water.

Q. 18: What is the basis for that expert opinion?

A. 18: (BG) The basis for my opinion is the direct testimony in Part 4. If the source of the water was the reactor cavity, that source is gone once the refueling outage is over, because the reactor cavity is not filled with water during operations. If the source of the water was theoretical condensation on the exterior of the drywell shell, new condensation ceases once the plant exits its outage because the shell would once again become hotter than the surrounding air.

Q. 19: What about water that might exist on the surface of the drywell shell at the end of the outage?

A. 19: (EWH) It would evaporate in a couple of hours. The temperature of the drywell shell during operations would evaporate any water on the external surface of the drywell shell that might be present at the end of an outage, regardless of the water's source. For example, for an internal drywell temperature of 130°F at elevation 10'3" (which is a reasonable assumption during power operations), I conservatively calculated the temperature of the air located between the exterior of the drywell shell and the concrete shield wall in the sand bed region, as 109.5°F. I calculated this temperature using a heat transfer analysis that uses the CFLUD computer code.

At these temperatures, a drying out rate of about 0.18 pounds per hour, per square foot (or 0.0022 gallons per hour, per sq ft), results. This is derived from the Carrier Equation (presented in American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE), Applications, 1995, section 4.6) for evaporation from ponds or pools: W = [95 + (37.4)(V)](Pw - Pa)/Hv (where: W = water evaporation rate, (lb/hr) per sq.ft. of the water's surface area; V = air velocity over the water's surface, miles/hr (which I assumed was zero); Pw = vapor pressure of water at the water temperature, inches of Hg; Pa = vapor pressure of water at the air dewpoint temperature, inches of Hg; and Hv = heat of vaporization of water at the pond water temperature, Btu/lb).

Assuming an initial and non-replenished water film thickness of 1/16 inch on the exterior of the drywell shell in the sand bed region, the water would be expected to fully evaporate in approximately two hours. I used 1/16 inch water film thickness because I believe it is extremely conservative. If I had selected 1/8 inch water film thickness, the total evaporation of the water would have taken twice as long.

Q. 20: Does this conclude your testimony regarding the exterior of the drywell shell in the sand bed region?

A. 20: (All) Yes.

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing it true and correct:

_________________________ 7/17/07

Barry Gordon Date

_________________________ _________________________

Michael P. Gallagher Date

_________________________ _________________________

Peter Tamburro Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing it true and correct:

Barry Gordon — Date

Michael P. Gallagher — 7-17-07

Michael P. Gallagher — Date

Peter Tamburro — Date

Edwin Hosterman — Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing it true and correct:

Barry Gordon Date

Michael P. Gallagher Date

Pet T 7/17/07

Peter Tamburro Date

Edwin Hosterman Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing is true and correct:

Edwin Hosterman   7-17-07

Edwin Hosterman   Date

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
E. Roy Hawkens, Chair
Dr. Paul B. Abramson
Dr. Anthony J. Baratta

In the Matter of:	)	July 20, 2007
AmerGen Energy Company, LLC	)	
	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

AMERGEN'S PRE-FILED DIRECT TESTIMONY PART 7 CONCLUSIONS

I. WITNESS BACKGROUND

Q. 1: Please state your name and current title.

A. 1: (MG) My name is Michael P. Gallagher, and I am Vice President of License Renewal for Exelon. I provided my witness information in Part 1 of this direct testimony.

(PT) My name is Peter Tamburro, and I am a Senior Mechanical Engineer in the Engineering Department at the Oyster Creek Nuclear Generating Station ("OCNGS"). I provided my witness information in Part 2 of this direct testimony.

Q. 2: Please summarize the purpose of your testimony.

A. 2: (All) The purpose of our testimony is to present AmerGen's conclusion regarding the adequacy of the frequency of UT measurements in the sand bed region of the OCNGS drywell shell for the purposes of license renewal, based on the previous six parts of pre-filed direct testimony.

II. CONCLUSIONS

Q. 3: Please summarize your overall conclusions.

A. 3: (All) The frequency of UT measurements every four years (*i.e.*, every other refueling outage), in conjunction with the other commitments that AmerGen has included as part of its Aging Management Program for the drywell shell, provides reasonable assurance that the drywell shell will continue to perform its intended functions of structural support and pressure containment in accordance with applicable ASME Code requirements and the Current Licensing Basis through the proposed license renewal period.

Q. 4: What is the basis for your conclusion?

A. 4: (All) Experts have testified that the bounding available margin of the drywell shell in the sand bed region for buckling is 0.064", and the bounding single point margin for pressure is 0.112". Experts have testified that the potential for continued corrosion of the external surface of the drywell shell in the sand bed region ceased in the early 1990s, when that surface of the shell was coated with a multi-layer epoxy coating system. Simply put, corrosion requires the ongoing presence of water, exposed metal, and oxygen. The epoxy coating system prevents water and oxygen from coming into contact with the underlying carbon steel drywell shell, thereby preventing additional corrosion. The fact that corrosion has been arrested is also supported by a comparison of the simple averages of the UT grid data from the interior of the drywell shell between the 1992 and 2006 refueling outages.

Experts have further testified that for corrosion to occur during the period of extended operation, this epoxy coating system—which was designed for harsher environments—would have to deteriorate. However, deterioration is not expected during the period of extended operation because none of the factors that would most likely contribute to deterioration of the coating, *i.e.*, mechanical damage, elevated temperature, submersion in water, high radiation, and ultraviolet light, are present.

The individuals who performed the visual (*i.e.*, VT-1) inspections of this epoxy coating system in 2006, and the individuals who reviewed the inspection reports, testified that the coating system is in excellent condition. If the coating system were nearing its end-of-life, it would show signs of embrittlement and attendant cracking, and these changes would occur over a long period of time. Such deterioration would be visible during the VT-1 inspections which are also performed no less frequently than every fours years (*i.e.*, every other refueling outage). The lack of deterioration is not surprising, because similar coating systems that have been in service for decades still do not exhibit signs of end-of-life deterioration.

Even if the epoxy coating system deteriorated to reveal the underlying carbon steel drywell shell during the period of extended operation, it would be repaired.

Also, any resulting corrosion would be detected and insignificant. Experts have testified that the corrosion products seeping through very localized defects in the coating, such as pinholes or holidays, would be detected during the VT-1 inspections even with corrosion rates as low as 0.002" per year. More widespread corrosion would also, of course, be detected during VT-1 inspections.

The resulting corrosion also would be insignificant because, as experts have testified, corrosion could only occur during those outages in which the refueling cavity is filled with water and the water enters the sand bed region and comes into contact with exposed metal of the drywell shell. Potential sources of water are limited to such outages because the only known source of water in the exterior sand bed region is the reactor cavity liner. While it is theoretically possible for the drywell shell temperature to drop below the ambient Reactor Building air temperature, and thus allow condensation on the exterior surface of the drywell shell in the sand bed region, this also could only occur during outages. Once the plant exits the outage, any water on the exterior of the drywell shell—regardless of its source—would quickly evaporate because the drywell shell would once again become hotter than the ambient air. If you limit corrosion to the refueling outages, and use Citizens' corrosion rate of 0.017", you could obtain only a loss of 0.0014" of metal between inspections.

The total corrosion of 0.0014" during a refueling outage, assuming that the epoxy coating system deteriorated to reveal the underlying carbon steel drywell shell, means that AmerGen's UT frequency of every four years provides more than reasonable assurance that the drywell shell in the sand bed region will continue to perform its intended functions in accordance with applicable ASME Code criteria for the license renewal period.

Q. 5: Does this conclude your testimony?

A. 5: (All) Yes.

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing it true and correct:

Michael P. Gallagher 7-17-07

Michael P. Gallagher Date

Peter Tamburro Date

In accordance with 28 U.S.C. § 1746, I state under penalty of perjury that the foregoing it true and correct:

Michael P. Gallagher Date

7/17/07

Peter Tamburro Date

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

In the Matter of:	)	July 20, 2007
AmerGen Energy Company, LLC	)	Docket No. 50-219
(License Renewal for Oyster Creek Nuclear Generating Station)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of the "AmerGen Energy Company, LLC's Initial Statement of Position," and "AmerGen's Pre-filed Direct Testimony," Parts 1 through 7, and associated exhibits were served this day upon the persons listed below, by e-mail and hand delivery, unless otherwise noted. Oversize exhibits were served by hand delivery only, unless otherwise noted.

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